An Independent Scientific Assessment of Well Stimulation in California

Volume II

Potential Environmental Impacts of Hydraulic Fracturing and Acid Stimulations

July 2015





Lawrence Berkeley
National Laboratory

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Volume II

Potential Environmental Impacts of Hydraulic Fracturing and Acid Stimulations

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CCST is a non-profit organization established in 1988 at the request of the California State Government and sponsored by the major public and private postsecondary institutions of California and affiliate federal laboratories in conjunction with leading private-sector firms. CCST's mission is to improve science and technology policy and application in California by proposing programs, conducting analyses, and recommending public policies and initiatives that will maintain California's technological leadership and a vigorous economy.

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Table of Contents

Introduction 1

1.1. Background 1

1.1.1. California Council on Science and Technology (CCST) Committee Process 5

1.1.2. Data and Literature Used in the Report 6

1.2. Assessing Impacts of Hydraulic Fracturing in California 7

1.2.1. Direct and Indirect Impacts of Hydraulic Fracturing and Acid Stimulation. 8

1.2.2. Impacts Covered in this Volume. 12

1.3. Conclusions and Recommendations 14

1.3.1. Direct and Indirect Impacts of Hydraulic Fracturing and Acid Stimulation 14

1.3.2. Management of Produced Water from Hydraulically Fractured or Acid Stimulated Wells 22

1.3.3. Protections to Avoid Groundwater Contamination by Hydraulic Fracturing 34

1.3.4. Emissions and their Impact on Environmental and Human Health 40

1.4. References 48

Impacts of Well Stimulation on Water Resources 49

2.1. Abstract 49

2.2. Introduction 52

2.3. Water Use for Well Stimulation in California 54

2.3.1. Current Water Use for Well Stimulation 54

2.3.2. Water Sources *57*

2.3.3. Water Use for Enhanced Oil Recovery *58*

2.3.4. Water Use for Well Stimulation in a Local Context *62*

2.4. Characterization of Well Stimulation Fluids 66

2.4.1. Understanding Well Stimulation Fluids *66*

2.4.2. Methods and Sources of Information *67*

2.4.3. Composition of Well Stimulation Fluids *70*

2.4.3.1. Chemicals Found in Hydraulic Fracturing Fluids *70*

2.4.3.2. Chemicals Found in Matrix Acidizing Fluids *72*

2.4.4. Characterization of Chemical Additives in Well Stimulation Fluids *74*

2.4.4.1. Characterization by Additive Function *74*

2.4.4.2. Characterization by Frequency of Use *75*

2.4.4.3. Characterization by Amount of Materials Used *77*

2.4.4.4. Characterization by Environmental Toxicity *77*

2.4.5. Selection of Priority Chemicals for Evaluation Based on Use and Environmental Toxicity *81*

2.4.6. Chemical Additives with Insufficient Information to be Fully Characterized *81*

2.4.7. Other Environmental Hazards of Well Stimulation Fluid Additives *82*

2.4.7.1. Chronic and Sublethal Effects of Chemicals *82*

2.4.7.2. Environmental Persistence *83*

2.4.7.3. Bioaccumulation *84*

2.5. Wastewater Characterization and Management 86

2.5.1. Overview of Oil and Gas Wastewaters 86

2.5.2. Recovered Fluids Generated from Stimulated Wells in California..... 88

2.5.2.1. Quantities of Recovered Fluids..... 88

3.5.2.3. Management of Recovered Fluids..... 94

2.5.3. Produced Water Generated from Stimulated Wells in California..... 94

2.5.3.1. Quantities of Produced Water..... 94

2.5.3.2. Chemical Constituents of Produced Water..... 96

2.5.3.3. Management of Produced Water..... 98

2.5.3.3.1. Produced Water from Onshore Oil and Gas Operations..... 98

2.5.3.3.2. Produced water from Offshore Oil and Gas Operations 102

2.6. Contaminant Release Mechanisms, Transport Pathways, and Driving Forces. 103

2.6.1. Overview of Contaminant Release Pathways..... 103

2.6.2. Potential Release Mechanisms to Water in California..... 104

2.6.2.1. Use of Unlined Pits for Produced Water Disposal..... 110

2.6.2.2. Injection of Produced Water into Protected Groundwater via Class II Wells 113

2.6.2.3. Reuse of Produced Water for Irrigated Agriculture 114

2.6.2.4. Treatment and Reuse of Oil and Gas Industry Wastewater..... 115

2.6.2.5. Disposal of Produced Water in Sanitary Sewer Systems..... 116

2.6.2.6. Leakage through Hydraulic Fractures..... 117

2.6.2.7. Leakage through Failed Inactive (Abandoned, Buried, Idle or Orphaned) Wells..... 122

2.6.2.8. Failure of Active Production, Class II, and Other Wells *123*

2.6.2.9. Leakage through Other Subsurface Pathways (Natural Fractures, Faults or Permeable Formations) *125*

2.6.2.10. Spills and Leaks *126*

2.6.2.11. Operator Error During Stimulation *128*

2.6.2.12. Illegal Discharges *128*

2.7. Impacts of Well Stimulation to Surface and Ground Water Quality 129

2.7.1. Studies that Found Evidence of Potential Water Contamination near Stimulation Operations *129*

2.7.2. Studies that Found No Evidence of Water Contamination Near Stimulation Operations *136*

2.7.3. Quality of Groundwater Near Stimulated Oil Fields in California *138*

2.8. Alternative Practices and Best Practices 143

2.8.1. Best Practices for Well Drilling, Construction, Stimulation, and Monitoring Methods *144*

2.8.2. Best and Alternative Practices for Well Stimulation Fluids *146*

2.8.2.1. Reuse Produced Water for Well Stimulation *146*

2.8.2.2. Use Alternative Water Supplies for Stimulation Fluids *147*

2.8.2.3. Apply Principals of Green Chemistry to Chemical Additives used in Stimulation Fluids *148*

2.8.2.4. Investigate Application of Waterless Technologies *149*

2.8.3. Best and Alternative Practices for Wastewater Characterization and Management *149*

2.8.3.1. Treat and Reuse Oil and Gas Wastewater for Other Beneficial Uses *149*

2.8.3.2. Characterize and Monitor Produced Water and Other Wastewaters ... *150*

2.8.3.3. Improve Management Practices for Oil and Gas Wastewater 151

2.8.4. Best and Alternative Practices for Monitoring for Groundwater Contamination 152

2.9. Data Gaps 153

2.9.1. Reports and Data Submissions Have Errors, Missing Entries, and Inconsistencies 153

2.9.2. Information is Not Easily Accessible to the Public 154

2.9.4. Information is Submitted in Inadequate Data Formats 154

2.9.4. Poor Collaboration Between State and Federal Data Collection Efforts .. 155

2.9.5. Chemical Information Submitted by Operators is Incomplete or Erroneous 155

2.9.6. Chemicals Lack Data on Characteristic Properties Needed for Environmental Risk Analysis 156

2.9.7. Data on Chemical Use from Conventional Oil and Gas Operations are Not Available 157

2.9.8. Lack of Data Regarding the Chemical Composition of Produced Water from Stimulated Wells 157

2.9.9. Incomplete Information Regarding Wastewater Management, Disposal, and Treatment Practices 158

2.9.10. Incomplete Information on the Impacts of Contamination from Subsurface Pathways 159

2.9.11. Lack of Accurate Information Regarding Old and Abandoned Wells..... 159

2.9.12. Lack of Knowledge about Fracture Properties in California 159

2.9.13. Incomplete Baseline Data and Monitoring Studies for Surface and Groundwater 160

2.9.14. Lack of Information on Spills 160

2.10. Main Findings 161

2.10.1. Water Use for Well Stimulation in California 161

2.10.2. Characterization of Well Stimulation Fluids 161

2.10.3. Wastewater Quantification, Characterization, and Management 163

2.10.4. Contaminant Release Mechanisms, Transport Pathways, and Impacts to Surface and Groundwater Quality 164

2.11. Conclusions 166

2.12. References 168

Air Quality Impacts from Well Stimulation 182

3.1. Abstract 182

3.2. Introduction 184

3.2.1. Chapter Structure 184

3.2.2. Classification of Sources of Well Stimulation Air Hazards 185

3.2.3. Greenhouse Gas Emissions Related to Well Stimulation 185

3.2.4. Volatile Organic Compounds and Nitrous Oxides Emissions Related to Well Stimulation 186

3.2.5. Toxic Air Contaminant Emissions Related to Well Stimulation 187

3.2.6. Particulate Matter Emissions Related to Well Stimulation 187

3.3.1. California Air Quality Concerns 187

3.3.2. Estimating Current Impacts of Oil and Gas Operations on California Air Quality 189

3.3.2.1. California Air Resources Board Field-Level Estimates of Greenhouse Gas Emissions from Oil Production 191

3.3.2.2. State-Level Emissions Inventories Produced by California Air Resources Board (CARB) 193

3.3.2.2.1. CARB GHG Inventory for Oil and Gas Operations 193

3.3.2.2.2. CARB Inventories for VOC and NOx (Smog-Forming) Emissions 198

3.3.2.2.3. CARB Inventories for TACs 207

3.3.2.2.4. SCAQMD Reporting of Hazardous Materials 221

3.3.2.2.5. Naturally Occurring Radioactive Materials 223

3.3.2.2.6. CARB Inventories for PM emissions 223

3.3.2.2.8. Natural Sources of Hydrocarbon-Related Air Emissions (Geologic Seeps) 228

3.3.2.2.9. Summary of CARB Inventories Treatment of WS Activities 228

3.3.2.3. State-Level Industry Surveys Produced by the California Air Resources Board (CARB) 229

3.3.2.3.1. Survey Methods 230

3.3.2.3.2. Survey Results 230

3.3.2.3.3. Survey Alignment with other California Inventories 232

3.3.2.4. Federal Emissions Inventories 233

3.3.2.5. Emissions From Silica Mining 235

3.3.3. Potentially Impacted California Air Basins 235

3.3.3.1. Status And Compliance in Regions of Concern 237

3.3.3.2. Likely Distribution of Impacts Across Air Basins 238

3.4. Hazards 239

3.4.1. Overview of Well-Stimulation-Related Air Hazards 239

3.4.2. Hazards due to Direct vs. Indirect Well Stimulation Impacts 242

3.4.2.1. Direct Well Stimulation Impacts 243

3.4.2.2. Indirect Well Stimulation Impacts *243*

3.4.3. Assessment of Air Hazard *244*

3.4.3.1. Greenhouse Gas Hazard Assessment *244*

3.4.3.2. Air Quality Hazard Assessment *244*

3.4.3.2.2. Well-Stimulation-Induced Air-Quality Hazard Assessment: Directly Emitted Species *245*

3.4.3.2.3. Well-Stimulation-Induced Air-Quality Hazard Assessment: Chemically Formed Species *246*

3.5. Alternative Practices to Mitigate Air Emissions 247

3.5.1. Regulatory Efforts to Prescribe Best Practices *247*

3.5.2. Control Technologies and Reductions *248*

3.6. Data Gaps 249

3.6.1. Bottom-Up Studies and Detailed Inventories *250*

3.6.1.1. Allen et al. (2013) Study of Hydraulic Fracturing Processes *250*

3.6.1.1.2. Overview of Study and Goals *250*

3.6.1.1.2. Methodology *250*

3.6.1.1.3. Key Findings *251*

3.6.1.2. City of Fort Worth Air Quality Study *251*

3.6.1.2.1. Overview of Study and Goals *251*

3.6.1.2.2. Study Methods *251*

3.6.1.2.3. Study Findings *252*

3.6.1.3. Alamo Area Council of Governments Eagle Ford Emissions Inventory . *252*

3.6.1.3.1. Overview of Study 252

3.6.1.3.2. Methods 252

3.6.1.4. Barnett Shale Special Inventory 252

3.6.1.4.1. Overview of Study 252

3.6.1.4.2. Methods 253

3.6.2. Top-Down Studies and Experimental Verification of California Air Emissions Inventories 253

3.6.2.1. Wunch et al. (2009) 255

3.6.2.2. Zhao et al. (2009) 255

3.6.2.3. Hsu et al. (2010) 256

3.6.2.4. Wennberg et al. (2012) 256

3.6.2.5. Peischl et al. (2013) 256

3.6.2.6. Jeong et al. (2013) 257

3.6.2.7. Jeong et al. (2014) 257

3.6.2.8. Johnson et al. (2014) 258

3.6.2.9. Gentner et al. (2014) 258

3.6.2.10. Summary Across Studies: How do Experimental Observations Align With California Inventory Efforts? 259

3.7. Findings 260

3.8. Conclusions 261

3.9. References 262

Seismic Impacts Resulting from Well Stimulation 267

4.1. Abstract 267

4.2. Introduction 268

4.2.1. Chapter Structure *268*

4.2.2. Natural and Induced Earthquakes *269*

4.2.3. Induced Seismicity Related to Well Stimulation *270*

4.3. Potential Impacts of Induced Seismicity 271

4.3.1. Building and Infrastructure Damage *272*

4.3.2. Nuisance from Seismic Ground Motion and Public Perception *272*

4.3.3. Mechanics of Earthquakes Induced by Subsurface Fluid Injection *272*

4.3.3.1. Tensile Fracturing *273*

4.3.3.2. Shear Failure on Pre-existing Faults and Fractures *273*

4.3.3.3. Factors Influencing the Probability of Occurrence of Induced Earthquakes *274*

4.3.3.4. Maximum Magnitude of Induced Earthquakes *274*

4.3.4. Induced Seismicity Resulting from Hydraulic Fracturing Operations *275*

4.3.5. Induced Seismicity Resulting from Wastewater Disposal *276*

4.4. Potential for Induced Seismicity in California 277

4.4.1. California Faults and Stress Field *278*

4.4.2. California Seismicity *279*

4.4.3. Correlation of Seismicity and Faulting with Injection Activity in California *282*

4.4.3.1. Depths and Volumes of California Wastewater Injection *282*

4.4.3.2. Locations of Wastewater Injection Wells Relative to Mapped Faults and Seismicity *284*

4.4.3.3. Preliminary Example of a Spatiotemporal Correlation Analysis *293*

4.4.4. Potential for Induced Seismicity on the San Andreas Fault *295*

4.5. Impact Mitigation 296

4.5.1. Induced Seismic Hazard and Risk Assessment 297

4.5.2. Protocols and Best Practices to Reduce the Impact of Induced Seismicity 298

4.6. Data Gaps 299

4.6.1. Injection Data 299

4.6.2. Seismic Catalog Completeness 300

4.6.3. Fault Detection 300

4.6.4. In-situ Stresses and Fluid Pressures 301

4.7. Findings 301

4.8. Conclusions 303

4.9. References 306

Potential Impacts of Well Stimulation on Wildlife and Vegetation 310

5.1. Abstract 310

5.2. Introduction 311

5.2.1. Overview of Chapter Contents 313

5.2.2. Regional Focus: Kern and Ventura Counties 313

5.2.2.1. Kern County: Ecology, Oil and Gas Development, and Well Stimulation 313

5.2.2.2. Ventura County: Ecology, Oil and Gas Development, and Well Stimulation 316

5.2.2.3. The Ecology of Kern and Ventura County Oil Fields 316

5.3. Assessment of Well Stimulation Impacts to Wildlife and Vegetation 321

5.3.1. Land Disturbance Causes Habitat Loss and Fragmentation 321

5.3.1.1. Overview and Literature Review of Habitat Loss and Fragmentation 321

5.3.1.2. Quantitative Analysis Of Hydraulic Fracturing-Enabled Production On Habitat Loss 323

5.3.1.2.1. Methods 323

5.3.1.2.2. Results and Discussion of Quantitative Analysis of Well Stimulation Impacts to Habitat Loss and Fragmentation 327

5.3.2. Human Disturbance Can Facilitate Colonization by Invasive Species 341

5.3.3. Discharges of Wastewater and Stimulation Fluids Can Affect Wildlife and Vegetation 342

5.3.3.1. Potential Pathways for Release of Fluids to the Environment 342

5.3.3.1.1. Exposure to Stimulation Fluids and Wastewater in Land and Freshwater Ecosystems 343

5.3.3.1.2. Discharges to the Ocean 346

5.3.3.2. Ecotoxicology of Well Stimulation Fluids and Wastewater 346

5.3.3.2.1. Stimulation Fluids 346

5.3.3.2.2. Inorganics in Wastewater 347

5.3.3.2.3. Hydrocarbons in Wastewater 347

5.3.3.3. Summary of Impacts of Discharges of Stimulation Fluids and Wastewater to Wildlife and Vegetation 348

5.3.4. Use of Water Can Harm Freshwater Ecosystems 348

5.3.5. Noise and Light Pollution Can Alter Animal Behavior 350

5.3.6. Vehicle Traffic Can Cause Plant and Animal Mortality 351

5.3.7. Ingestion of Litter Can Cause Condor Mortality *351*

5.3.8. Potential Future Impacts to Wildlife and Vegetation *352*

5.4. Laws and Regulations Governing Impacts to Wildlife and Vegetation from Oil and Gas Production 353

5.5. Measures to Mitigate Oil Field Impacts on Terrestrial Species and Their Habitats 355

5.5.1. Habitat Disturbance Mitigation *356*

5.5.1.1. Compensatory habitat *356*

5.5.1.2. Disturbance minimization *357*

5.5.1.3. Habitat degradation mitigation *358*

5.5.2. Avoidance of Direct Take *358*

5.5.3. Environmental Restoration *361*

5.5.4. Employee Training *362*

5.5.5. Regional Species-Specific Measures *362*

5.5.6. Efficacy of Mitigation Measures *362*

5.5.6.1. Use of Barriers to Exclude Blunt-Nosed Leopard Lizards *362*

5.5.6.2. Use of Topsoil Salvage to Conserve Hoover's Wooly-Star *363*

5.5.6.3. Habitat Restoration for San Joaquin Valley Listed Species *363*

5.6. Assessment of Data Quality and Data Gaps 363

5.7. Findings 365

5.8. Conclusions 366

5.9. References 367

Potential Impacts of Well Stimulation on Human Health in California 374

6.1. Abstract 374

6.2. Introduction 375

6.2.1. Framing the Hazard and Risk Assessment Process 378

6.2.2. Scope of Community and Occupational Health Assessment 380

6.2.3. Overview of Approach and Chapter Organization 381

6.2.4. Summary of Environmental Public Health Hazards and Risk Factors 384

6.3. Public Health Hazards of Unrestricted Well Stimulation Chemical Use 389

6.3.1. Approach for Human Health Hazard Ranking of Well Stimulation Chemicals 390

6.3.1.1. Chemical Hazard Ranking Approach 390

6.3.1.2. Acute Toxicity Hazard Screening Criterion 392

6.3.1.3. Chronic Toxicity Hazard Screening Criterion 393

6.3.2. Results of Human-Health Hazard Ranking of Stimulation Chemicals 394

6.3.2.1. Hazard Ranking of Chemicals Added to Hydraulic Fracturing Fluids 394

6.3.2.2. Hazard Ranking of Acidization Chemicals 398

6.3.2.3. Hazard Summary of Air Pollutants that are Related to Well Stimulation Fluid 401

6.3.3. Literature Summary of Human Health Hazards Specific to Well Stimulation 403

6.4. Water Contamination Hazards and Potential Human Exposures 404

6.4.1. Summary of Risk Issues Related to Water Contamination Pathways 404

6.4.1.1. Disposal of Produced Water in Unlined Pits 405

6.4.1.2. Public Health Hazards of Produced Water Use for Irrigation of Agriculture *405*

6.4.1.3. Public Health Hazards of Shallow Hydraulic Fracturing..... *406*

6.4.1.4. Leakage Through Wells *406*

6.4.1.5. Injection Into Usable Aquifers..... *406*

6.4.2. Literature on Water Contamination from Well Stimulation *407*

6.4.2.1. Exposure to Water Pollutants *407*

6.4.2.2. Oil and Gas Recovered and Produced Water *408*

6.5. Air Emissions Hazards and Potential Human Exposures..... 409

6.5.1. Emissions Characterized in Chapter 3 ..... *410*

6.5.2. Potential Health-Relevant Exposure Pathways Identified in the Current Literature..... *411*

6.5.2.1. Air Emissions Exposure Potential..... *411*

6.5.2.2. Emissions and Potential Exposures from Equipment and Infrastructure *412*

6.5.3. Public Health Studies of Toxic Air Contaminants *413*

6.5.3.1. Methods for Peer Review of Scientific Literature..... *414*

6.5.3.2. Results from the Environmental Public Health Literature Review..... *416*

6.5.3.3. Public Health Outcome Studies..... *417*

6.5.4. Summary of Public Health Outcome Studies *420*

6.6. Occupational Health-Hazard Assessment Studies..... 420

6.6.1. Scope of Industry and Workforce in California..... *421*

6.6.2. Processes and Work Practices *422*

6.6.3. Acid Used in Oil and Gas Wells..... *423*

6.6.3.1. Occupational Health Outcomes Associated With Well Stimulation-Enabled Oil and Gas Development *428*

6.6.3.2. Worker Protection Standards, Enforcement, and Guidelines for Well Stimulation Activities *428*

6.7. Other Hazards 429

6.7.1. Noise Pollution *430*

6.7.2. Light Pollution *431*

6.7.3. Biological Hazards *432*

6.8. Community and Occupational Health Hazard Mitigation Strategies 432

6.8.1. Community Health Mitigation Practices *433*

6.8.1.1. Setbacks *433*

6.8.1.2. Reduced Emission Completions and Other Air Pollutant Emission Reduction Technological Retrofits *433*

6.8.1.3. Use of Produced Water for Agricultural Irrigation *434*

6.8.1.4. Water Source Switching *434*

6.8.2. Occupational Health Mitigation Practices *434*

6.8.2.1. Personal Protective Equipment *434*

6.8.2.2. Reducing Occupational Exposure to Silica *435*

6.9. Data Gaps 435

6.10. Conclusions 436

6.11. Recommendations 438

6.11.1. Recommendation Regarding Chemical Use *438*

6.11.2. Recommendation Regarding Exposure and Health-Risk Information Gaps *438*

6.11.3. Recommendation on Community Health 439

6.11.4. Recommendation on Occupational Health 439

6.12. References 440

List of Figures

Figure 1.2-1. The sequential parts of the well stimulation system considered in this report. 8

Figure 1.3-1. Maps of (a) Kern and (b) Ventura Counties showing the increase in well density attributable to hydraulic fracturing-enabled development and land use/land cover between 1977 and 2014.. 22

Figure 1.3-2. Percolation pits in Kern County used for produced water disposal 23

Figure 1.3-3. Location of percolation pits in the Central Valley and Central Coast used for produced water disposal. 25

Figure 1.3-4. Produced water used for irrigation in Cawelo water district. 27

Figure 1.3-5. A map of the Elk Hills field in the San Joaquin Basin showing the location of wells that have probably been hydraulically fractured 29

Figure 1.3-6. High-precision locations for earthquakes M≥3 in central and southern California during the period 1981-2011 31

Figure 1.3-7. Disposal method for produced water from hydraulically fractured wells during the first full month after stimulation for the time period 2011-2014 33

Figure 1.3-8. Shallow fracturing locations and groundwater quality in the San Joaquin and Los Angeles Basins. 36

Figure 1.3-9. Depths of groundwater total dissolved solids (TDS) in mg/L in five oil fields in the Los Angeles Basin. 37

Figure 1.3-10. Distribution of crude oil greenhouse gas intensity for fields containing well-stimulation-enabled pools 41

Figure 1.3-11. Summed facility-level toxic air contaminant (TAC) emissions in San Joaquin Valley air district) 43

Figure 1.3-12. Population density within 2,000 m (6,562 ft) of currently active oil production wells and currently active wells that have been stimulated 45

Figure 2.2-1. Five stages of the hydraulic fracturing water cycle. 52

Figure 2.6-5. Distribution of (a) stimulation heights and (b) stimulation lengths in California. 119

Figure 2.7-1. Minimum total dissolved solids concentration from GAMA in 5 by 5 kilometer (3 by 3 mile) square areas in central and southern California geologic basins with oil production. 140

Figure 2.7-2. Minimum total dissolved solids concentration from GAMA in 5 by 5 kilometer (3 by 3 mile) square areas in central and southern California geologic basins with oil production. 142

Figure 2.7-3. Minimum total dissolved solids concentration from GAMA in 5 by 5 kilometer (3 by 3 mile) square areas in central and southern California geologic basins with oil production. 143

Figure 4.4-10. Spatiotemporal analysis of a seismicity cluster in the Santa Maria Basin..... 294

Figure 5.2.1. Maps of the San Joaquin Valley from pre-European settlement to the year 2000. 315

Figure 5.2.3. Well density in the southern San Joaquin (and Cuyama) basins..... 320

Figure 5.2.4. Well density in Ventura Basin. Opaque blue, yellow and red indicate the density of wells, both stimulated and unstimulated..... 320

Figure 5.3.2. Maps of the San Joaquin Basin showing the increase in well density attributable to hydraulic fracturing-enabled development and key ecological features. 334

Figure 5.3.3. Maps of the Ventura Basin showing the increase in well density attributable to hydraulic fracturing-enabled development and key ecological features..... 336

Figure 5.3.4. Land use and habitat types impacted by hydraulic-fracturing-enabled production in California..... 338

Figure 6.6-1. Evaluation of the flammability, reactivity, and physical hazards of chemical additives reported for hydraulic fracturing in California..... 427

List of Tables

Table 1.1-1. Well stimulation technologies included in Senate Bill (SB 4)..... 2

Table 1.2-1. Examples of direct and indirect impacts considered in this study..... 11

Table 1.3-1. Availability of information for characterizing the hazard of stimulation chemicals used in hydraulic fracturing. 17

Table 2.3-1. Estimated volume of water use for oil and gas well stimulation operations in California under current conditions. 56

Table 2.3-2. Water sources for well stimulation according to 480 well stimulation completion reports filed from January 1, 2014 to December 10, 2014..... 58

Table 2.3-3. Breakdown of injected water for enhanced oil recovery by source and type of water, in million m^3 per year, in 2013. 60

Table 2.3-4. Estimated annual water use for well stimulation and hydraulic fracturing-enabled EOR by water resources Planning Area..... 63

Table 2.3-5. Estimated annual water use for well stimulation and hydraulic fracturing-enabled EOR in the Semitropic Planning Area compared to applied water volumes estimated by DWR for 2010..... 65

Table 2.4-1. Sources for physical, chemical, and toxicological information for chemicals used in well stimulation treatments in California..... 69

Table 2.4-2. Seven compounds submitted to DOGGR in a Notice of Intent to perform matrix acidizing that were publicly available between December 2013 and June 2014 that were not found in voluntary notices reported for hydraulic fracturing to the FracFocus Chemical Disclosure Registry 72

Table 2.4-3. Chemicals used for matrix acidizing in California, as reported in DOGGR's Well Stimulation Treatment Disclosure Reports prior to May 5, 2015 that were not reported for hydraulic fracturing in the FracFocus Chemical Disclosure Registry 73

Table 2.4-4. Hydraulic fracturing chemical use in California by function, where function was positively identified. 75

Table 2.4-5. Twenty most commonly reported hydraulic fracturing components

in California, excluding base fluids (e.g., water and brines) and inert mineral proppants and carriers. 76

Table 2.4-6. The most toxic hydraulic fracturing chemical additives used in California with respect to acute aquatic toxicity, based on the United Nations Globally Harmonized System (GHS) of Classification and Labeling of Chemicals system. 79

Table 2.4-7. Comparison of results between standard test organisms and California native and resident species. 80

Table 2.5-1. A comparison of total recovered fluid and injected fluid volumes for stimulated wells located throughout California, as reported in DOGGR completion reports as of Dec 15, 2014 (N=505). 89

Table 2.5-2. Chemical analyses reported for recovered fluids collected from stimulated wells in North and South Belridge. 92

Table 2.5-3. Produced water disposition during the first full month after stimulation and post stimulation to the present, January 1, 2011-June 30, 2014. 99

Table 2.5-4. Produced water disposition by evaporation-percolation during the first full month after stimulation by field, January 1, 2011 – June 20, 2104. 100

Table 2.5-5. Produced water disposition by subsurface injection during the first full month after stimulation, by county, January 1, 2011 – June 30, 2014. 101

Table 2.6-1. Activities and associated release mechanisms for the different stages of well stimulation 105

Table 2.6-2. Assessment of release mechanisms associated with stimulation operations for their potential to impact surface and groundwater quality in California. 107

Table 2.7-1. Examples of release mechanisms and contamination incidents associated with oil and gas activities in the United States. 133

Table 2.7-2. Some regulatory limits regarding total dissolved solids in water. 139

Table 3.2-1. Global warming potential of well-stimulation-relevant air emissions. 186

Table 3.3-1. Coverage of different assessment methods and key sources for each method. 190

Table 3.3-2. CARB GHG inventory emissions of interest for WS. 194

Table 3.3-3. CARB criteria pollutant inventory sector/subsector pairings of interest for oil and gas and well stimulation emissions. 198

Table 3.3-4. CARB ROG/CO stationary source inventory emissions sources and material drivers of emissions within the broad categories “Oil and Gas Production” and “Oil and Gas Production (Combustion)..... 199

Table 3.3-5. CARB mobile source inventory emissions sources within the category “Off road, oil drilling and workover, diesel (unspecified)” taken from SJV and SC air district data. 201

Table 3.3-6. CARB criteria pollutant overview in emissions of criteria pollutants in t per day (1,000 kg/d). 207

Table 3.3-7. Overall toxics inventory results for indicator species in SJV region. 212

Table 3.3-8. Overall toxics inventory results for indicator species in SC region. 213

Table 3.3-9. SIC codes used in analysis of facility-level TAC emissions. 215

Table 3.3-10. Emissions rates from stationary facilities in SJV region, as reported to facility-level reported TACs database..... 218

Table 3.3-11. Emissions rates from stationary facilities in SC region, as reported to facility-level reported TACs database..... 219

Table 3.3-12. San Joaquin Valley oil and gas facility-reported emissions of ten indicator TACs compared to California Toxics Inventory estimates for all sources, both for year 2010. 220

Table 3.3-13. South Coast oil and gas facility-reported emissions of ten indicator TACs compared to California Toxics Inventory estimates for all sources, both for year 2010. 221

Table 3.3-14. TAC species associated with fracturing fluids extracted from SCAQMD dataset. 222

Table 3.3-15. TAC species associated in matrix acidizing extracted from SCAQMD dataset. 222

Table 3.3-16. Dust emissions contribution to overall PM emissions in the SJV region .. 227

Table 3.3-17. PM10 from dust emissions from unpaved traffic areas (non-road), tonnes per year (1,000kg/y).....228

Table 3.3-18. Results from CARB 2007 oil and gas industry survey.....231

Table 3.3-19. Results from CARB 2007 oil and gas industry survey, presented by business type. 231

Table 3.3-20. Results from CARB 2007 oil and gas industry survey, presented by air district. 232

Table 3.3-21. Emissions reporting categories for GHGRP subpart W, reproduced from the FLIGHT tool. 234

Table 3.3-22. Results from GHGRP subpart W, presented by production basin for California.....234

Table 3.3-23. Attainment status for PM2.5 in the main oil and gas producing regions.....238

Table 3.4-1. TAC emissions ranked by mass emissions rate from oil and natural gas production source category, reproduced from U.S. EPA risk assessment. 241

Table 3.5-1. Best control or practices for controlling emissions from key processes.....249

Table 4.6-1. Summary of minimum magnitudes of complete detection, M_c, in onshore oil-producing basins.....301

Table 5.3.1. Description of well density categories used in this study.....325

Table 5.3.2. Categories of land use, land cover, and natural communities used in this assessment. 327

Table 5.3.3. The effect of hydraulic-fracturing-enabled production on well density in California oil and gas fields. 328

Table 5.3.4. Hectares by county and all of California for areas developed for oil and gas production.....337

Table 5.3.5. Number of occurrences of listed species within 2 km of a field with at least 200 hectares of altered habitat.....340

Table 5.3.5. Reported sump locations in California.....344

Table 6.2-1. Summary of human health hazards and risk factors in California substantiated with California-specific data. 385

Table 6.3-1. Available and unavailable information for characterizing the hazard of stimulation chemicals used in hydraulic fracturing..... 395

Table 6.3-2. A list of the 12 substances used in hydraulic fracturing with the highest acute Estimated Hazard Metric (EHM_{acute}) values along with an indication of what factor(s) contribute most to their ranking 396

Table 6.3-3. A list of the 12 substances used in hydraulic fracturing with the highest chronic Estimated Hazard Metric (EHMchronic) values along with an indication of what factor(s) contribute most to their ranking..... 397

Table 6.3-4. Available and unavailable information for characterizing the hazard of stimulation chemicals use in acidizing..... 399

Table 6.3-5. A list of the 10 substances used in acidization with the highest acute Estimated Hazard Metric (EHM_{acute}) values, along with an indication of what factor(s) contribute most to their ranking 400

Table 6.3-6. A list of the 10 substances used in acidization with the highest chronic Estimated Hazard Metric (EHMchronic) values along with an indication of what factor(s) contribute most to their ranking 401

Table 6.3-7. The substances used in hydraulic fracturing and acidization that are also listed on the California TAC Identification List..... 402

Table 6.6-1. Employment in oil and gas extraction – California 2014..... 421

Table 6.6-2. Work processes and health hazards associated with well stimulation. 426

Table 6.7-1. WHO thresholds levels for effects of night noise on population health. 430

Table 6.7-2. Equipment Noise Levels for Drilling and Production in Hermosa Beach, California. 431

Acronyms and Abbreviations

AACOG	Alamo Area County of Governments
ACGIH	American Conference of Governmental Industrial Hygienists
ACS	American Chemical Society
ACToR	Aggregated Computational Toxicology Resource
ADSA	Axial Dimensional Stimulation Area
ANSS	Advanced National Seismic System
APCD	Air Pollution Control District
API	American Petroleum Institute
AQMD	Air Quality Management District
ATSDR	Agency for Toxic Substances and Disease Registry
ATV	All-Terrain Vehicles
AXPC	American Exploration and Production Council
bbl	Barrels
BC	Black Carbon
BLM	Bureau of Land Management
BLS	(U.S.) Bureau of Labor Statistics
BO	Biological Opinion
BOD5	Biological Oxygen Demand
BTEX	Benzene, Toluene, Ethylbenzene, and Xylenes
C_2H_6	Ethane
CALGEM	California Greenhouse Gas Emissions Measurement program
CalOSHA	California Occupational Safety and Health Administration
CalWIMS	California Well Information Management System
CARB	California Air Resources Board
CAS	Chemical Abstracts Service
CASRN	Chemical Abstracts Service Registry Number
CDFW	California Department of Fish and Wildlife
CDPH	California Department of Public Health
CEIDARS	California Emission Inventory Development and Reporting System
CEQA	California Environmental Quality Act
CESA	California Endangered Species Act
CGS	California Geological Survey
CH_4	Methane
CHRIP	Chemical Risk Information Platform
CNDDB	California Natural Diversity Database

CO	Carbon Monoxide
CO2	Carbon Dioxode
CO2eq.	CO2-equivalent
COD	Chemical Oxygen Demand
CTI	California Toxics Inventory
CTMs	Chemical Transport Models
CVRWQCB	Central Valley Regional Water Quality Control Board
CWD	Cawelo Water District
dB	Decibels
dBA	A-Weighted Decibels
DBNPA	2,2-dibromo-3-nitrilopropionamide
DFW	Department of Fish and Wildlife
DOC	(California) Department of Conservation
DOGGR	Division of Oil, Gas, and Geothermal Resources
DOORS	Diesel Off-road On-line Reporting System
DWR	Department of Water Resources
EC	Electrical Conductivity
EC_{50}	Median Effective Concentration
ECHA	European Chemicals Agency
EDC	Endocrine Disrupting Compounds
EDGAR	Emissions Database for Global Atmospheric Research
EDTA	Ethylenediaminetetraacetic Acid
EGS	Enhanced Geothermal System
EHM	Estimated Hazard Metric
EOR	Enhanced Oil Recovery
EPI	Estimation Program Interface
ERCB	Energy Resources Conservation Board
ERG/SAGE	Eastern Research Group, Inc. and Sage Environmental Consulting LP
ESA	Endangered Species Act (Federal)
EU	European Union
EWQL	Environmental Water Quality Laboratory
GAMA	Groundwater Ambient Monitoring and Assessment
GAO	U.S. Government Accountability Office
GHG	Greenhouse Gas
GHGRP	Greenhouse Gases Reporting Program
GHS	Globally Harmonized System
GIS	Geographic Information System
GWP	Global-Warming Potential
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutants

HBACV	Health-Based Air Comparison Values
HC	Hydrocarbon
HCl	Hydrochloric Acid
HCP	Habitat Conservation Plan
HCF	Hydroflourocarbons
HF	Hydrofluoric Acid
HI	Hazard Indices
HSDB	Hazardous Substance Data Bank
IARC	International Agency for Research on Cancer
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRIS	Integrated Risk Information System
IUCLID	International Uniform Chemical Information Database
LBNL	Lawrence Berkeley National Laboratory
LC_{50}	Median Lethal Concentration
LCA	Life Cycle Assessment
LCFS	Low Carbon Fuel Standard
LD_{50}	Median Lethal Dose
LPG	Liquefied Petroleum Gas
MADL	Maximum Allowable Dose Levels
MBNPA	2-bromo-3-nitrilopropionamide
MCL	Maximum Contaminant Level
MF	Microfiltration
MIT	Methylisothiazolinone
MITI	Ministry of International Trade and Industry
MRL	Minimal Risk Levels
MRR	Mandatory Reporting Regulation
MSDS	Material Safety Data Sheets
MTBE	Methyl Tertiary Butyl Ether
N_2O	Nitrous Oxide
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NF	Nanofiltration
NGWA	National Groundwater Association
NIOSH	National Institute for Occupational Safety and Health
NIOSH REL	NIOSH Reference Exposure Level
NMVOC	Non-Methane Volatile Organic Compounds
NORM	Naturally Occurring Radioactive Materials
NO_x	Nitrogen Oxides
NP	Not Practical

NPDES	National Pollution Discharge Elimination System
NRC	National Research Council
NSRL	No Significant Risk Levels
NYSDEC	New York State Department of Environmental Conservation
OC	Organic Carbon
OCS	(Federal) Outer Continental Shelf
OECD	Organization for Economic Cooperation and Development
OEHHA	Office of Environmental Health Hazard Assessment
OES	Office of Emergency Services
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
OSHA	Occupational Safety and Health Administration
OSPAR	Oslo-Paris Convention, also known as the Convention for the Protection of the Marine Environment of the North-East Atlantic
PA	Planning Area
PA DEP	Pennsylvania Department Of Environmental Protection
PAH	Polycyclic Aromatic Hydrocarbons
PBZ	Personal Breathing Zone
PEL	Permissible Exposure Limits
PFC	Perflourocarbons
PHG	Public Health Goals
PM	Particulate Matter
POTW	Publicly Owned Treatment Works
PPE	Personal Protective Equipment
ppm	Parts Per Million
PSE	PSE Healthy Energy
PSHA	Probabilistic Seismic Hazard Assessment
PSR	Physicians for Social Responsibility
QAC	Quaternary Ammonium Compounds
QCEW	Quarterly Census Of Employment And Wages
REL	Reference Exposure Levels
RfC	Reference Concentrations
RfDs	Reference Doses
RMSE	Root Mean Square Error
RO	Reverse Osmosis
ROG	Reactive Organic Gases
SAF	San Andreas Fault
SB 4	Senate Bill 4
SB 1281	Senate Bill 1281
SC	South Coast
SCAQMD	South Coast Air Quality Management District

SCEDC	Southern California Earthquake Data Center
SF_6	Sulfur hexaflouride
SFs	Slope Factors
SIC	Standard Industrial Classification
SJV	San Joaquin Valley
SNMOC	Speciated Non-Methane Organic Compounds
SoCAB	South Coast Air Basin
SWP	State Water Project
SWRCB	State Water Resources Control Board
TAC	Toxic Air Contaminant
TDS	Total Dissolved Solids
TENORM	Technologically Enhanced Naturally Occurring Radioactive Material
TLV	Threshold Limit Value
TOC	Total Organic Carbon
TOC	Toxic Organic Compound
TOG	Total Organic Gases
TOXNET	National Library of Medicine, Toxicology Data Network
TPH	Total Petroleum Hydrocarbons
TRPH	Total Recoverable Petroleum Hydrocarbons
TWA	Time Weighted Average
UCL	Upper Confidence Level
UCSB	University of California, Santa Barbara
UF	Uncertainty Factor
UF	Ultrafiltration
UGRB	Upper Green River Basin
UIC	Underground Injection Control
UR	Unit Risk Values
URE	Unit Risk Estimates
U.S. DOE	U.S. Department of Energy
U.S. EIA	U.S. Energy Information Administration
U.S. EPA	U.S. Environmental Protection Agency
USDW	Underground Source of Drinking Water
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
USQFF	United States Quaternary Fault and Fold
V/P	Various/Partial
VOC	Volatile Organic Carbon
WS	Well Stimulation
WST	Well Stimulation Treatment
WTR	Well to the Refinery Entrance Gate

Chapter One

Introduction

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1.1. Background

In 2013, the California Legislature passed Senate Bill 4 (SB 4), setting the framework for regulation of well stimulation technologies in California, including hydraulic fracturing. SB 4 also requires the California Natural Resources Agency to conduct an independent scientific study of well stimulation technologies in California. SB 4 stipulates that the independent study assess current and potential future well stimulation practices, including the likelihood that these technologies could enable extensive new petroleum production in the state; evaluate the impacts of well stimulation technologies and the gaps in data that preclude this understanding; identify potential risks associated with current practices; and identify alternative practices that might limit these risks. (See Box 1.1-1 for a short history of oil and gas production in California.) This scientific assessment addresses well stimulation used in oil and gas production both on land and offshore in California.

This study is issued in three volumes. Volume I, issued in January 2015, describes how well stimulation technologies work, how and where operators deploy these technologies for oil and gas production in California, and where they might enable production in the future. Volume II, the present volume, discusses how well stimulation could affect water, atmosphere, seismic activity, wildlife and vegetation, and human health. Volume II reviews available data, and identifies knowledge gaps and alternative practices that could avoid or mitigate these possible impacts. Volume III, also issued in July 2015, presents case studies that assess environmental issues and qualitative risks for specific geographic regions. A final Summary Report summarizes key findings, conclusions and recommendations of all three volumes.

Well stimulation enhances oil and gas production by making the reservoir rocks more permeable, thus allowing more oil or gas to flow to the well. The reports discuss three types of well stimulation as defined in SB 4 (Table 1.1-1 and Volume I, Chapter 2). The first type is “hydraulic fracturing.” To create a hydraulic fracture, an operator increases the pressure of an injected fluid in an isolated section of a well until the surrounding rock breaks, or “fractures.” Sand injected into these fractures props them open after the pressure is released. The second type is “acid fracturing,” in which a high-pressure acidic fluid fractures the rock and etches the walls of the fractures, so they remain permeable

after the pressure is released. The third type, "matrix acidizing," does not fracture the rock; instead, acid pumped into the well at relatively low pressure dissolves some of the rock and makes it more permeable.

Table 1.1-1. Well stimulation technologies included in Senate Bill (SB 4).

<table>
<tr><th colspan="3">Hydraulic Fracturing Stimulation</th></tr>
<tr><td colspan="3">Common feature:
All treatments create sufficient pressure in the well to induce fractures in the reservoir.</td></tr>
<tr><td colspan="2">Proppant Fracturing:
Uses proppant to retain fracture permeability</td><td>Acid Fracturing:
Uses acid instead of proppant</td></tr>
<tr><td>Traditional Fracturing:
Creates long, narrower hydraulic fractures deep into the formation for stimulating flow through lower-permeability reservoirs; proppant injected into fractures to retain fracture permeability</td><td>Frac-Pack:
Creates short, wider hydraulic fractures near wells within higher-permeability reservoirs; objectives are bypassing regions near-the wellbore damaged by drilling and preventing sand from the reservoir entering the well</td><td>Similar to traditional fracturing, but uses acid instead of proppant to retain fracture permeability by etching, or "roughening" the fracture walls; only used in carbonate reservoirs</td></tr>
</table>

<table>
<tr><th colspan="2">Acidizing Stimulation</th></tr>
<tr><td colspan="2">Common feature: All treatments use acid to dissolve materials impeding flow</td></tr>
<tr><td colspan="2">Matrix Acidizing:
Dissolves material in the near-well region to make the reservoir rocks more permeable; typically only used for reservoirs that are already permeable enough to not require traditional or acid fracturing</td></tr>
<tr><td>Sandstone Acidizing:
Uses hydrofluoric acid in combination with other acids to dissolve minerals (silicates) that plug the pores of the reservoir; only used in reservoirs composed of sandstone or other siliceous rocks</td><td>Carbonate Acidizing:
Uses hydrochloric acid (or acetic or formic acids) to dissolve carbonate minerals, such as those comprising limestone, and bypass rock near the wellbore damaged by drilling; only used in carbonate reservoirs</td></tr>
</table>

Box 1.1-1. The History of Oil and Gas Production in California

California has some highest concentrations of oil in the world and oil and gas production remains a major California industry. For example, Long Beach oil field, in the Los Angeles Basin, once contained about ~ 5 billion m3 (3 billion barrels) of oil within an area of less than 7 km2 (2,000 acres). Four of the ten largest conventional U.S. oil fields are in California: Midway-Sunset, Kern River, and South Belridge in the San Joaquin Basin and Wilmington-Belmont in the Los Angeles Basin. According to the Division of Oil, Gas, and Geothermal Resources (DOGGR) there are 52 giant oil fields in the state, each with more than 16 million m3 (100 million barrels) of known recoverable oil, and many other fields of various sizes. California's oil production ranks third in the nation, behind Texas and North Dakota and provides about 20,000 jobs.

Oil has been exploited since prehistoric times, first by Native Americans and later by Spanish colonists and Mexican residents, who routinely collected “brea” from the numerous natural oil seeps. Commercial production started in the middle of the nineteenth century from hand-dug pits and shallow wells. Exploratory drilling began in the 1860s and 1870s and boomed in the first half of the Twentieth Century. In 1929, at the peak of oil development in the Los Angeles Basin, California accounted for more than 22% of total world oil production (American Petroleum Institute, 1993). California’s oil production reached an all-time high of almost 64 million m3 (400 million barrels) in 1985 and has generally declined since then. By 1940 all but four of the giant onshore fields had been discovered. San Ardo, South Cuyama, and Round Mountain were discovered in the 1940s, and the last, Yowlumne field, was discovered in1974. Today California is the third highest producing state, with about 6% of US production but less than 1% of global production. In 1960, almost as much oil was produced in California as was consumed, but by 2012 Californians produced only 32% of the oil they used (31.5 million m3, or 198 million barrels produced in the state out of a total of about 98.7 million m3, or 621 million barrels consumed). Californian’s mainly made up the shortfall of about 67.3 million m3 (423 million barrels) mainly with oil delivered by tanker from Alaska, Saudi Arabia, Ecuador, Iraq, Colombia, and other countries.

Over the years, water flooding, gas injection, thermal recovery, hydraulic fracturing, and other techniques have been used to enhance oil and gas production as California fields mature. Water flooding involves injecting water into a reservoir, causing additional oil to flow to production wells. Water flooding was first used in the Los Angeles Basin in 1956 at Wilmington-Belmont field to mitigate subsidence, with the incidental benefit of increased oil recovery. By the 1960s the method had been widely deployed in many fields around the state as an effective means of augmenting production.

California has substantial heavy oil that must be liquefied with heat to make it flow to a well. Steam injection (steam flooding and soak), the most commonly used “thermal recovery” method, involves injecting steam into wells interspersed among production wells. Nearly all production at Kern River field and much of the production from Midway Sunset and many other California fields is heavy oil produced by thermal recovery. Since 1989, when DOGGR first reported oil recovered by water flooding and steam injection, over 70% of production can be attributed to these energy-intensive techniques (DOGGR, 1990; DOGGR, 2010).

The diatomite reservoirs in the western San Joaquin Valley contain billions of barrels of oil in rocks that are not very permeable, and can only be produced with hydraulic fracturing—now accounting for about 20% of California oil and gas production (see Volume I, Chapter 3).

The first offshore oil production in the United States began in 1897 on piers in Santa Barbara County. The first Federal Outer Continental Shelf (OCS) lease sale was held in 1966 and production began from a platform in 1969. That same year a well failure on Union Oil Platform A in Dos Cuadras field, not far from the Santa Barbara Coast, spilled

15,899 m3 (100,000 barrels) in ten days and made a deep negative impression on public opinion that has constrained offshore development ever since. In 1984 a moratorium on development in the Federal OCS went into effect. Billions of barrels of recoverable oil probably remain in the federal offshore, but with no new leases, OCS production has been steadily declining since 1996.

California's oil production reached an all-time high of almost 64 million m3 (400 million barrels) in 1985 and has generally declined since then. In 1960, almost as much oil was produced in California as was consumed, but by 2012 Californians used about 67.3 million m3 (423 million barrels) more than they produced (Figure 1.1-1) with the shortfall mainly delivered by tanker from Alaska, Saudi Arabia, Ecuador, Iraq, Colombia and other countries.

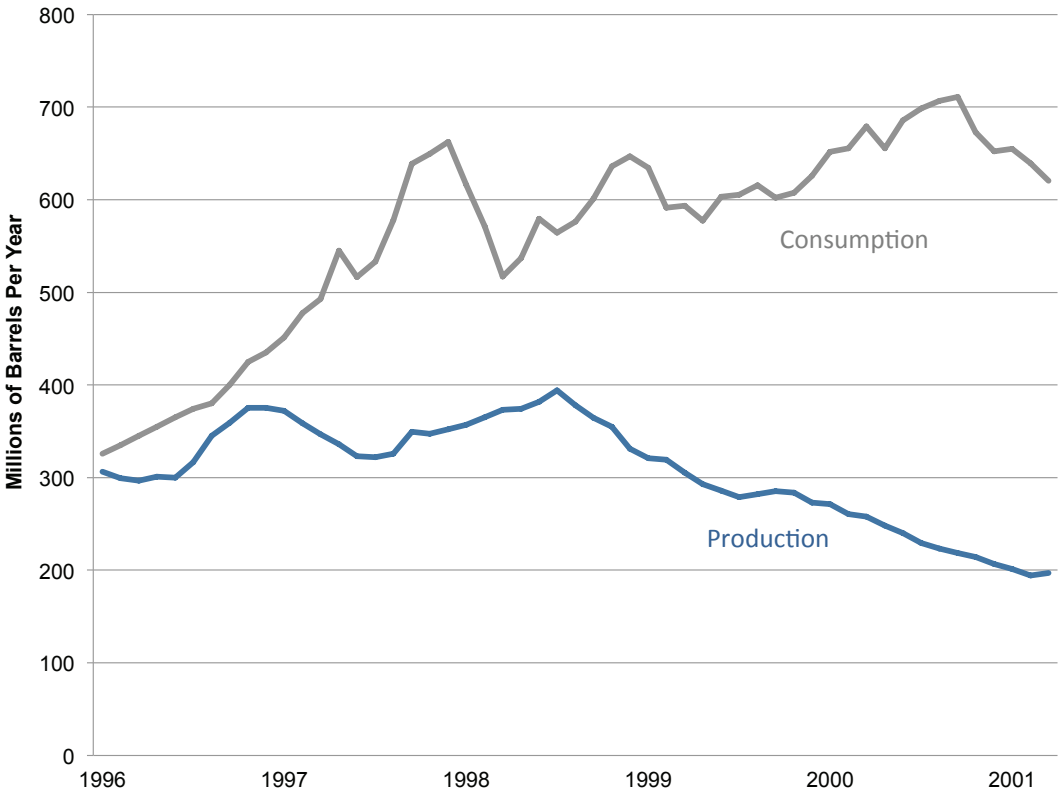


Figure 1.1-1. Total oil production (blue line) and consumption (grey line) from all sources in California from 1960 to 2012 (Data: US EIA, 2014a and b).

Natural gas is much less abundant than oil in California and most of the state's natural gas production is a co-product of oil development, referred to as "associated" gas production. Only the Sacramento Basin has significant non-associated natural gas production, but about three quarters of the gas production in the state is not from dry gas wells, but from wells that primarily produce oil, mostly in the San Joaquin Valley.

1.1.1. California Council on Science and Technology (CCST) Committee Process

The California Council on Science and Technology (CCST) organized and led the study reported on here. Members of the CCST steering committee were appointed based on technical expertise and a balance of technical viewpoints. (Volume II, Appendix B provides information about CCST's Steering Committee.) Under the guidance of the Steering Committee, Lawrence Berkeley National Laboratory (LBNL) and subcontractors (the science team) developed the findings based on the literature review and original technical data analyses. Volume II, Appendix C provides information about the LBNL science team and subcontractors who authored Volumes I, II, and III of this report. The science team reviewed relevant literature and conducted original technical data analyses.

The science team studied each of the issues required by SB 4, and the science team and the steering committee collaborated to develop a series of conclusions and recommendations that are provided in this summary report. Both science team and steering committee members proposed draft conclusions and recommendations. These were modified based on discussion within the steering committee along with continued consultation with the science team. Final responsibility for the conclusions and recommendations in this report lies with the steering committee. All steering committee members have agreed with these conclusions and recommendations. Any steering committee member could have written a dissenting opinion, but no one requested to do so.

SB 4 also required the participation of the California Environmental Protection Agency's Office of Environmental Health Hazard Assessment (OEHHA) in this study. OEHHA provided toxicity and other risk assessment information on many of the chemicals used in hydraulic fracturing, offered informal technical advice during the course of the study, and provided comments on drafts of Volumes II and III. OEHHA also organized a February 3, 2015 public workshop in Bakersfield in which representatives of CCST, LBNL, and subcontractors heard comments from attendees on the topics covered in the report.

This report has undergone extensive peer review. (Peer reviewers are listed in Volume II, Appendix F: "California Council on Science and Technology Study Process"). Seventeen reviewers were chosen for their relevant technical expertise. More than 1,500 anonymous review comments were provided to the authors. The authors revised the report in response to peer review comments. In cases where the authors disagreed with the reviewer, the response to review included their reasons for disagreement. Report monitors then reviewed the response to review and when satisfied, approved the report.

1.1.2. Data and Literature Used in the Report

This assessment reviews and analyzes both existing data and scientific literature, with preference given to findings in the peer-reviewed scientific literature. The study included both voluntary and mandatory reporting of stimulation data, as well as non-peer reviewed reports and documents if they were topically relevant and determined to be scientifically credible by the authors and reviewers of this volume. Finally, the California Council on Science and Technology solicited and reviewed nominations of literature from the public, employing specific criteria for material as described in Volume I, Appendix E, "Review of Information Sources." The science team did not collect any new data, but did do original analysis of available data.

Volumes I, II and III of this report address issues that have very different amounts of available information and cover a wide range of topics and associated disciplines, which have well established but differing protocols for inquiry. In Volume I, available data and methods of statistics, engineering and geology allowed the authors to present the factual basis of well stimulation in California. With a few exceptions, the existing data was sufficient to identify the technologies used, where and how often they are used, and where they are likely to be used in the future (see Volume I Chapter 3). This volume, Volume II, faces the challenge of presenting the impacts of well stimulation. Since many impacts have never been thoroughly investigated, the authors drew on literature describing conditions and outcomes in other places, circumstantial evidence and expert judgment to catalog a complete list of potential impacts. Volume II also identifies a set of concerning situations – "risk factors" (summarized in Appendix D of the Summary Report and Table 6.2-1 of this volume)-- that warrant a closer look and perhaps regulatory attention. We believe this flexible and appropriate use of different (but well established) methods of inquiry under highly variable conditions of data availability and potential impacts serves useful to California.

The SB 4 completion reports provide reliable data to assess certain potential environmental and health impacts such as the use of fresh water for hydraulic fracturing. For most potential impacts, however, only incomplete information and data exist. Few scientific studies of the health and environmental impacts of well stimulation have been conducted to date, and the ones that have been done focus on other parts of the country, where practices differ significantly from present-day practices in California. Generally, environmental baseline data has not been collected in the vicinity of stimulation sites before stimulation. The lack of baseline data makes it difficult to know if the process of stimulation has changed groundwater chemistry or habitat, or how likely any potential impacts might be. No records of contamination of protected water by hydraulic fracturing fluids in California exist, but few targeted studies have been conducted to look for such contamination. Data describing the quality of groundwater near hydraulic fracturing sites is not universally available. The requirement for groundwater monitoring in SB 4 addresses this issue by requiring groundwater monitoring when protected water is present. Applications for hydraulic fracturing operations in locations that have no nearby

protected groundwater have been exempted from groundwater monitoring. Consequently information is now being gathered about the quality of water near proposed hydraulic fracturing sites, but the SB 4 requirements have only been in place since 2013.

A complete analysis of the risks posed by well stimulation (primarily hydraulic fracturing) to water contamination, air pollution, earthquakes, wildlife, plants, and human health requires much more data than that available. However, the study authors were able to draw on their technical knowledge, data from other places, and consideration of the specific conditions in California to identify conditions in California that deserve more attention and make recommendations for additional data collection, increased regulation, or other mitigating measures.

1.2. Assessing Impacts of Hydraulic Fracturing in California

This scientific assessment of hydraulic fracturing and acid stimulation impacts covers the application of hydraulic fracturing and acid stimulation technology and resulting oil and gas production activities. The report considers impacts and potential impacts resulting from the development of a well pad and support infrastructure required to drill the well, hydraulic fracturing or acid stimulation and completion, production of oil and/or natural gas, and disposal or reuse of produced water. Figure 1.2-1 shows the parts of the oil and gas system included in this assessment and examples of impacts for each.

This report excludes other stages in the development, production, refining, and use life cycle of oil and gas, including impacts of manufacturing of materials or equipment used in stimulation, impacts of transport of produced oil and gas to refineries or providers, impacts of refining, or impacts of combustion of hydrocarbons as fuel.

Existing California regulations, including the state's new well stimulation regulations effective July 1, cover many of the areas of potential concern or risk raised in this study, 2015. This study does not address the effectiveness of the current regulatory framework in mitigating any potential risks associated with well stimulation technologies, but recommends that the state conduct such assessments in the future.

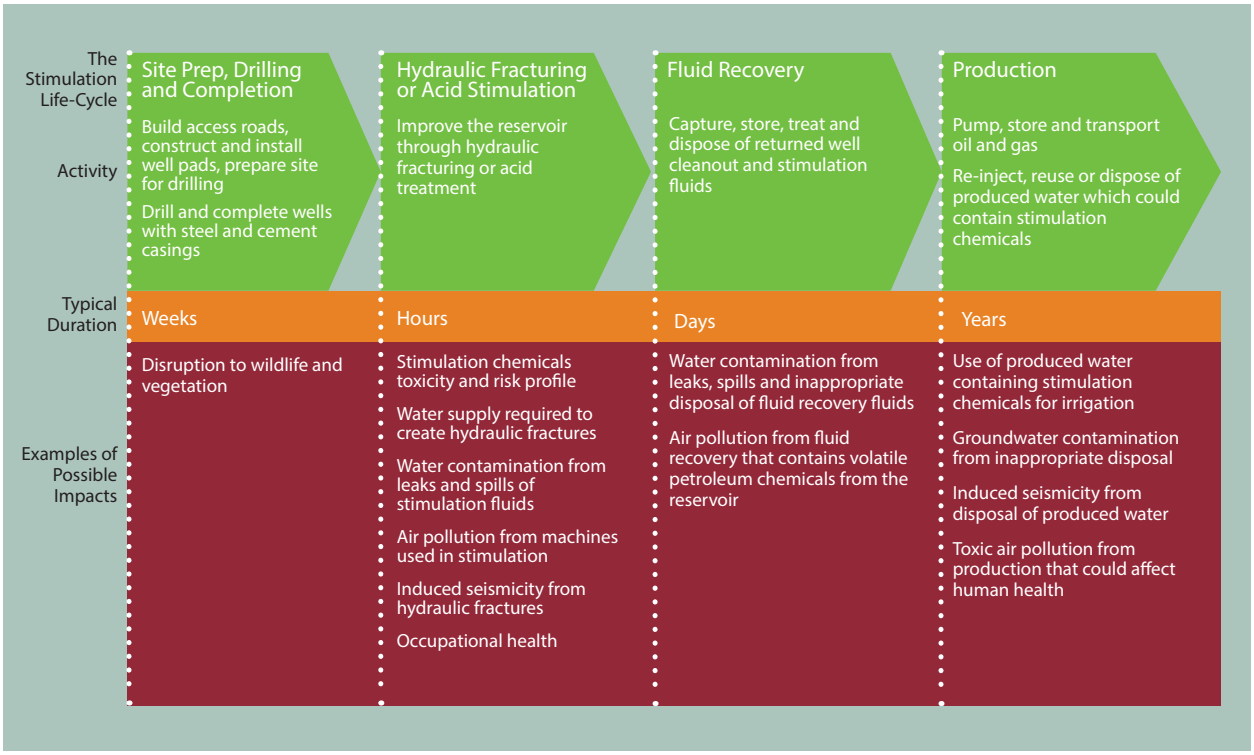


Figure 1.2-1. The sequential parts of the well stimulation system considered in this report.

1.2.1. Direct and Indirect Impacts of Hydraulic Fracturing and Acid Stimulation.

Hydraulic fracturing or acid stimulation can cause direct impacts. Potential direct impacts might include a hydraulic fracture extending into protected groundwater, accidental spills of fluids containing hydraulic fracturing chemicals or acid, or inappropriate disposal or reuse of produced water containing hydraulic fracturing chemicals. These direct impacts do not occur in oil and gas production unless hydraulic fracturing or acid stimulation has occurred. This study covers potential direct impacts of hydraulic fracturing or acid stimulation.

Hydraulic fracturing or acid stimulation can also incur indirect impacts, i.e., those not directly attributable to the activity itself. Some reservoirs require hydraulic fracturing for economic production. All activities associated with oil and gas production enabled by hydraulic fracturing or acid stimulation can bring about indirect impacts. Indirect impacts of hydraulic-fracturing-enabled oil and gas development usually occur in all oil and gas development, whether or not the wells are stimulated.

In some cases, we cannot separate direct and indirect impacts. For example, the inventory of emissions of hazardous air pollutants is for all oil and gas production and does not differentiate between hydraulically fractured and unfractured wells, so the data do not

support differentiating direct and indirect impacts. However, as illustrated in the following examples, differentiating direct and indirect impacts can be important for framing investigations and policy.

An indirect impact common to all production, not just production enabled by hydraulic fracturing, means the impacts incurred by just the hydraulically fractured wells represent a small subset of the problem. For example, disposal of produced water through underground injection may carry the risk of inducing an earthquake. If this produced water comes from a hydraulically fractured reservoir, this potential impact would be an indirect impact. In California, about 20% of all produced waters come from stimulated reservoirs. Understanding induced seismicity requires looking at all the wastewater injections, not just those generated by hydraulically fractured wells. In this case, the indirect impact attributed to hydraulically fractured wells represents a small part of a larger problem.

As another example, studies show elevated health risks near hydraulically fractured reservoirs attributable to benzene (Volume II, Chapter 6). But benzene use has been phased out in hydraulic fracturing fluids. These health risks probably occur due to processes associated with oil production, because oil contains benzene naturally. In this case, the health impacts do not occur because of hydraulic fracturing itself; they are indirect impacts that occur because of production. So the same health impacts could occur near any production, whether the wells have been fractured or not. Research that focuses only on benzene impacts near hydraulically fractured wells will likely result in a very poor understanding of both the extent of this problem and the possible mitigation measures. Concern about hydraulic fracturing might lead to studying health effects near fractured wells, but concern about the health effects from benzene should lead to study of all types of oil and gas production, not just hydraulically fractured wells.

As a final example, the activities associated with hydraulic fracturing or acid stimulation can add some new direct occupational hazards to a business that already has substantial occupational hazards. The drilling, completion, and production phases common to all oil and gas production incur significant risk of exposure to many toxic substances and accidents. In general, oil and gas production has significant occupational health issues, but these impacts are not directly attributable to well stimulation activity. In hydraulic fracturing, silica sand used for the proppant in hydraulic fracturing presents an additional occupational health hazard for serious lung disease (silicosis). Potential exposure to silica is a direct impact of hydraulic fracturing and a relatively small part of the total hazard profile for oil and gas development.

While this project was not tasked with a full assessment of the impacts of all oil and gas development in California, we have described indirect impacts in the context of all oil and gas production where the issue and associated data either allows or requires this. This report does include some recommendations for assessment of certain impacts for all oil and gas development in the future.

Table 1.2-1 describes the potential direct impacts of hydraulic fracturing and acid stimulation, plus potential indirect impacts of hydraulic-fracturing-enabled oil and gas development covered in this report.[1] The table includes issues of concern named in the SB 4 legislation or issues that have been raised by the public in the various forums around California and the U.S. regarding well stimulation or were identified by expert judgment. A long list of features, events, and processes related to well stimulation and production could possibly lead to harmful impacts, but these are not all likely or equally likely. A long list of plausible hazards have been described in Volume II, but the reader is cautioned to treat these as a "checklist" of possible impacts, not at all a list of impacts that are generally occurring. Existing regulations prevent or mitigate many of these risks; however, an evaluation of the effectiveness of this regulatory framework was beyond the scope of this study.

Out of the possible plausible hazards, some emerge as especially relevant potential risk factors worthy of further attention through additional data collection or increased scrutiny. Chapter 6 presents a table of these risk issues, which are also the basis of the conclusions and recommendations in this chapter.

1. We do not include indirect impacts of acid stimulation because based on existing data, we did not find reservoirs that required acid stimulation for production.

Table 1.2-1. Examples of direct and indirect impacts considered in this study.

Issue	Possible Direct Impact	Possible Indirect Impact of Hydraulic-Fracturing-Enabled Oil and Gas Development
Stimulation Chemicals	Chemicals used in stimulation create the potential for introduction of hazardous materials into the environment.	N/A
Water Use	Stimulation uses California fresh water supply.	Freshwater is sometimes used to produce oil in a previously stimulated reservoir, e.g., enhanced oil recovery via injection of water or steam.
Water Supply	Stimulation chemicals could enter produced water that is otherwise of sufficient quality for beneficial uses, such as irrigation, making treatment more complicated.	Additional production enabled by hydraulic fracturing can lead to additional produced water, which, with appropriate treatment, may be of sufficient quality for beneficial uses.
Water Contamination	Intentional or accidental releases of stimulation chemicals and their reaction products could lead to contamination of fresh water supply. Risk of hydraulic fractures acting as conduit for accidental releases of fluids; and risk of high-pressure injection affecting integrity of existing wells.	N/A
Air pollution	Equipment used in stimulation emits pollutants and greenhouse gases (GHGs). Retention ponds and tanks used to store stimulation fluids could contain off-gassing volatile organic compounds (VOC).	Oil and gas development activities cause emissions including VOC emissions from produced water.
Induced Seismicity	Hydraulic fracturing could cause earthquakes.	Disposal of wastewater from hydraulic fracture-enabled production in disposal wells classified by the EPA's Underground Injection Control (UIC) program as "Class II"[1] could cause earthquakes.
Human Health	Releases of stimulation chemicals that pollute water and air, as well as noise and light pollution from the stimulation operation could affect public health.	Proximity to any oil production, including stimulation-enabled production, could result in hazardous emissions to air and water, and noise and light pollution that could affect public health.
Wildlife and Vegetation	Introduction of invasive species; contamination of habitat or food web by stimulation chemicals; and water use for stimulation fluids could impact wildlife and vegetation.	Habitat loss and fragmentation, introduction of invasive species, and water use for enabled enhanced oil recovery could impact wildlife and vegetation.

1. Class II wells are underground injection wells that inject fluids associated with oil and natural gas production. There are three types of Class II wells: enhanced recovery, wastewater disposal, and hydrocarbon storage. For more information, see http://water.epa.gov/type/groundwater/uic/class2/index.cfm.

1.2.2. Impacts Covered in this Volume

The chapters of this volume assess, to the extent possible, the potential impacts of well stimulation on water, air, seismicity, habitat and human health.

Chapter 2 analyzes the hazards and potential impacts of well stimulation on California's water resources including water use in well stimulation, the volumes, chemical compositions, and potential hazards of stimulation fluids, and the characteristics of wastewater including production, management, and the potential release mechanisms and transport pathways by which well stimulation chemicals enter the water environment. The chapter addresses the following questions and for each evaluates the available data, identifies data gaps and ways to mitigate or avoid potential impacts:

- What are the volumes of fresh water used for well stimulation in California, and what are the sources of these supplies (e.g., domestic water supplies, private groundwater wells, irrigation sources)? How does water use for well stimulation compare with other uses in California and in the regions where well stimulation is occurring?

- What are the volumes and chemical compositions—including types of chemicals and quantities—of stimulation fluids? What are the physical, chemical, and toxicological properties of the stimulation chemicals used? To what extent does this chemical use create hazards for and potential impacts on water resources in California?

- What volumes of recovered fluids and produced water are generated from stimulated wells and what are the chemical compositions of those waters? Are volumes of produced water generated from stimulated wells and non-stimulated wells different? Does the chemical composition of produced water from stimulated wells differ from that of non-stimulated wells? What techniques are used to recover fluids and manage produced water (e.g., deep well injection, unlined sumps)? Could existing treatment technologies remove well stimulation chemicals that are being used in California?

- What are the release mechanisms and transport pathways by which well stimulation chemicals could enter surface water and groundwater aquifers? Could the introduction of stimulation chemicals into the environment affect ecosystems and human health (through contamination of aquifers, spills, inappropriate uses of wastewater, etc.)?

Chapter 3 assesses the potential of well stimulation to emit greenhouse gases (GHGs), volatile organic compounds (VOCs), oxides of nitrogen (NO_x), toxic air contaminants (TACs), and particulate matter (PM). Because oil and gas development in general can also have these impacts, the purpose of this chapter is to evaluate what is known about the contribution of well stimulation to general impacts from oil and gas development.

Well stimulation could impact air quality via emission of a large variety of chemical species. These species can have local, regional, or global impacts, mediated by the regional atmospheric transport mechanisms and the natural removal mechanisms relevant for that species. For clarity, this report groups species into four categories of interest, each with unique potential impacts.

1. Greenhouse gases (GHGs);

2. Reactive organic gases (ROGs), and oxides of nitrogen (NO_x) that cause photochemical smog generation;

3. Toxic air contaminants (TACs, a California-specific designation similar to federal designation of hazardous air pollutants (HAPs); and

4. Particulate matter (PM), including dust.

The chapter describes methods of classifying well-stimulation-related air impacts, and the major sources and types of emissions from oil and gas activities. The chapter also describes the treatment of well-stimulation-related emissions in current California emissions inventories. Then, the chapter evaluates the California regions likely to be affected by the use of well-stimulation technology, current best practices for managing air quality impacts of well stimulation, and gaps in data and scientific understanding surrounding well-stimulation-related air impacts.

Chapter 4 assesses the potential for induced seismicity in California caused by injection of fluids into the subsurface. The vast majority of earthquakes induced by fluid injection are too small to be felt at the ground surface. However, induced seismicity can produce felt or, in rare cases, damaging ground motions. Large volumes of water injected over long time periods (i.e. months to years) into zones in or near potentially active earthquake sources can induce earthquakes. This chapter reviews the current state of knowledge about induced seismicity, and the data and research required to determine the potential for induced seismicity in California, including along the San Andreas Fault. The chapter also discusses how existing protocols could be improved to lower the risk from induced seismicity in California.

Chapter 5 evaluates the potential impact of well stimulation on wildlife and vegetation, and how these impacts depend on the density of oil and gas wells and other human land uses in the area. The chapter describes how the impacts of oil and gas production to native wildlife and vegetation depend on the prevailing land use. In some regions, well stimulation takes place in areas where wild habitat has already been displaced by near-continuous well pads or agricultural and urban development. However, in oil fields with little other development and a relatively low density of oil wells, oil and gas development could more directly impact valuable native habitat. Because habitat loss and fragmentation is likely to have the greatest impact on wildlife and vegetation, the chapter explores

this topic in greater depth by quantifying habitat loss and fragmentation attributable to well-stimulation-enabled hydrocarbon production. Other potential impacts, such as the introduction of invasive species, releases of harmful fluids to the environment, diversion of water from waterways, noise and light pollution, vehicle collisions, ingestion of litter by wildlife, and the possible release of well stimulation chemicals into the environment are described. Then the chapter reviews regulation of the oil and gas industry with respect to impacts on wildlife and vegetation. The chapter describes measures to mitigate oil field impacts on terrestrial species and their habitats, and major data gaps and ways to remedy the gaps.

Chapter 6 addresses health hazards associated with community and occupational environmental exposures *directly* attributable to well stimulation and *indirect* exposures due to oil and gas development that were facilitated by stimulation in California. The chapter evaluates hazards directly attributable to well stimulation stemming from the chemicals used in stimulation that might contact humans through contaminated water (described in Chapter 2) and air pollution hazards associated with oil and gas development described in Chapter 3 for human health.

1.3. Conclusions and Recommendations

The following conclusions and recommendations are numbered to correspond to the full set of conclusions and recommendations as given in the Summary Report, but only those conclusions and recommendations that derive from this volume are given below. This is the reason that the conclusions and recommendations are not numbered sequentially starting with number 1. For the sake of consistency, some conclusions include information from other volumes as noted.

1.3.1. Direct and Indirect Impacts of Hydraulic Fracturing and Acid Stimulation

Conclusion 3.1. Direct impacts of hydraulic fracturing appear small but have not been investigated.

Available evidence indicates that impacts caused directly by hydraulic fracturing or acid stimulation or by activities directly supporting these operations appear smaller than the indirect impacts associated with hydraulic-fracturing-enabled oil and gas development, or limited data precludes adequate assessment of these impacts. Good management and mitigation measures can address the vast majority of potential direct impacts of well stimulation.

Hydraulic fracturing in California lasts a relatively short amount of time near the beginning of production—less than a day—and requires relatively small fluid volumes. In contrast, the subsequent oil and gas production phase lasts for years and involves very large volumes of fluid, with potential for long-term perturbations of the environment. Consequently, the production phase following well stimulation can have a much larger impact than the stimulation phase.

This study identifies a number of possible pathways for direct impacts from hydraulic fracturing and acid stimulation, such as accidental spills or leaks of hydraulic fracturing or acid fluids or emissions of volatile organic compounds (VOCs) from hydraulic fracturing fluids. Many, if not all, of these potential direct impacts can be addressed with good management practices or mitigation measures. These are described in Volumes II and III.

The recommendations below provide specific measures that could eliminate, avoid, or ameliorate direct impacts. These measures include limiting the use of toxic chemicals, avoiding inappropriate disposal, managing beneficial use of produced water containing stimulation chemicals, providing extra due diligence for shallow fracturing near protected groundwater, and using "green completions" to control emissions in oil and gas wells.

In California, existing or pending regulation already addresses many of these direct impacts. The state's new well stimulation regulations, going into effect on July 1, 2015, will likely avoid or reduce many, but not all, of the impacts described in this report. The scope of this study did not include judging the adequacy of existing regulation, but this would make sense at some later time when significant experience can be assessed.

Recommendation 3.1. Assess adequacy of regulations to control direct impacts of hydraulic fracturing and acid stimulations.

Over the next several years, relevant agencies should assess the adequacy and effectiveness of existing and pending regulations to mitigate direct impacts of hydraulic fracturing and acid stimulations, such as to: (1) reduce the use of highly toxic or harmful chemicals, or those with unknown environmental profiles in hydraulic fracturing and acid fluids; (2) devise adequate treatment and testing for any produced waters intended for beneficial reuse that may include hydraulic fracturing and acid fluids or disallow this practice; (3) prevent shallow hydraulic fractures from intersecting protected groundwater (Volume II); (4) dispose of produced waters that contain stimulation chemicals appropriately; and (5) control emissions, leaks and spills.

Conclusion 3.2. Operators have unrestricted use of many hazardous and uncharacterized chemicals in hydraulic fracturing.

The California oil and gas industry uses a large number of hazardous chemicals during hydraulic fracturing and acid treatments. The use of these chemicals underlies all significant potential direct impacts of well stimulation in California. This assessment did not find recorded negative impacts from hydraulic fracturing chemical use in California, but no agency has systematically investigated possible impacts. A few classes of chemicals used in hydraulic fracturing (e.g., biocides, quaternary ammonium compounds, etc.) present larger hazards because of their relatively high toxicity, frequent use, or use in large amounts. The environmental characteristics of many chemicals remain unknown. We lack information to determine if these chemicals would present a threat to human health or the environment if released to groundwater or other environmental media. Application of green chemistry principles, including reduction of hazardous chemical use and substitution of less hazardous chemicals, would reduce potential risk to the environment or human health.

Operators have few, if any, restrictions on the chemicals used for hydraulic fracturing and acid treatments. The state's regulations address hazards from chemical use and eliminate or minimize many, but not necessarily all risks. Some of the chemicals used present hazards in the workplace or locally, such as silica dust or hydrofluoric acid. Other chemicals present potential hazards for the environment, such as biocides and surfactants that, if released, can harm fish and other wildlife. Many of the chemicals used can harm human health. If well stimulation did not use hazardous chemicals, hydraulic fracturing would pose a much smaller risk to humans and the environment. Even so, hazardous chemicals only present a risk to humans or the environment if they are released in hazardous concentrations or amounts, persist in the environment, and actually reach and affect a human, animal or plant. Even a very toxic or otherwise harmful chemical presents no risk if no person, animal or plant receives a dose of the chemical. Characterization of the risk posed by chemical use requires information on both the hazards posed by the chemicals and information about exposure to the chemicals (in other words, risk = hazard x exposure).

We have established a list of chemicals used in California based on voluntary disclosures by industry. In California, oil and gas production operators have voluntarily reported the use of over 300 chemical additives. New state regulations under SB 4 will eventually reveal all chemical use. However, knowledge of the hazards and risks associated with all the chemicals remains incomplete for almost two-thirds of the chemicals (Table 1.3-1). The toxicity and biodegradability of more than half the chemicals used in hydraulic fracturing remains uninvestigated, unmeasured, and unknown. Basic information about how these chemicals would move through the environment does not exist. Although the probability of human and environmental exposure is estimated to be low, no direct studies of environmental or health impacts from hydraulic fracturing and acid stimulation chemicals have been completed in California. To the extent that any hydraulic fracturing and acid stimulation fluids can get into the environment, reduction or elimination of the use of the most hazardous chemicals will reduce risk.

Table 1.3-1. Availability of information for characterizing the hazard of stimulation chemicals used in hydraulic fracturing. The Chemical Abstracts Service Registry Number (CASRN) is a unique numerical identifier assigned to chemical substances. Operators do not provide CASRN numbers for proprietary chemicals.

Number of chemicals	Proportion of all chemicals	Identified by unique CASRN	Impact or toxicity	Quantity of use or emissions
172	55%	Available	Available	Available
17	5%	Available	Available	Unavailable
6	2%	Available	Unavailable	Available
121	38%	Unavailable	Unavailable	Available

For this study, we sorted the extensive list of chemicals reported in California to identify those of most concern or interest and created tables identifying selected chemicals for each category contributing to hazard (see Summary Report, Appendix H, and Volume II, Chapters 2 and 6). Chemicals used most frequently or in high concentrations rise to a higher level of concern, as do chemicals known to be acutely toxic to aquatic life or mammals. The assessment included chemicals used in hydraulic fracturing that can be found on the Toxic Air Contaminant Identification List, the Proposition 65 list of chemicals known to the State of California to cause cancer and reproductive harm, and the OEHHA list of chemicals with published reference exposure limits. Additional hazards considered include, flammability, corrosivity, and reactivity. These various criteria allow identification of priority chemicals to consider when reducing potential hazards from chemical use during well stimulation.

Strong acids, strong bases, silica, biocides, quaternary ammonium compounds, nonionic surfactants, and a variety of solvents are used frequently and in high concentrations in hydraulic fracturing and acid stimulation. Strong acids, strong bases, silica, and many solvents present potential exposure hazards to humans, particularly during handling, and of are of particular concern to workers and nearby residents. Use of appropriate procedures minimizes the risk of exposure and few incidences of the release of these materials during oil and gas development have been reported in California.

Biocides, quaternary ammonium compounds, nonionic surfactants, and some solvents present a significant hazard to aquatic species and other wildlife, particularly when released into surface water. The study found no releases of hazardous hydraulic fracturing chemicals to surface waters in California and no direct impacts to fish or wildlife. However, there is concern that well stimulation chemicals might have been released and potentially contaminated groundwater through a variety of mechanisms (see Conclusions 4.1, 4.3, 4.4, 5.1, 5.2 below). Many of the chemicals used in well stimulation, such as surfactants, are more harmful to the environment than to human health, but all of these chemicals are undesirable in drinking water. Determining whether chemicals that have been released pose an actual risk to human health or the environment requires further study, including a better understanding of the amounts of chemicals released and persistence of those chemicals in the environment.

Green Chemistry principles attempt to maintain an equivalent function while using less toxic chemicals and smaller amounts of toxic chemicals. It may be possible to forego or reduce the use of the most hazardous chemicals without losing much in the way of functionality. Chemical substitutions can present complications and can also introduce a new set of hazards and require a careful adaptive approach. For example, the use of guar in hydraulic fracturing fluids introduces food to bacteria in the reservoir, and this increases the need for biocides to prevent the buildup of toxic gases generated by bacterial growth. Operators moving to a less toxic but less effective biocide might also need to move away from guar to a less-digestible substitute. Then this choice could introduce new hazards instead of old hazards. For these reasons, the American Chemical Society currently sponsors a Green Chemistry Roundtable on the topic of hydraulic fracturing.

The state could also limit the chemicals used in hydraulic fracturing by disallowing certain chemicals or limiting chemicals to those on an approved list where approval depends on the chemical having an acceptable environmental profile. The latter approach reverses the usual practice, whereby an industry is permitted to use a chemical until a regulatory body proves that the chemical is harmful. Oil and gas production in the environmentally sensitive North Sea uses this pre-approval approach and might provide a model for limiting chemical risk in California. The EPA Designed for the Environment (DFE) list of chemicals may also be useful. Of course, any of these approaches requires that the operators report the unique identifier (CASRN number) of all chemicals.

Recommendation 3.2. Limit the use of hazardous and poorly understood chemicals.

Operators should report the unique CASRN identification for all chemicals used in hydraulic fracturing and acid stimulation, and the use of chemicals with unknown environmental profiles should be disallowed. The overall number of different chemicals should be reduced, and the use of more hazardous chemicals and chemicals with poor environmental profiles should be reduced, avoided, or disallowed. The chemicals used in hydraulic fracturing could be limited to those on an approved list that would consist only of those chemicals with known and acceptable environmental hazard profiles. Operators should apply Green Chemistry principles to the formulation of hydraulic fracturing fluids, particularly for biocides, surfactants, and quaternary ammonium compounds, which have widely differing potential for environmental harm. Relevant state agencies, including DOGGR, should as soon as practical engage in discussion of technical issues involved in restricting chemical use with a group representing environmental and health scientists and industry practitioners, either through existing roundtable discussions or independently (Volume II, Chapters 2 and 6).

Conclusion 3.3. The majority of impacts associated with hydraulic fracturing are caused by the indirect impacts of oil and gas production enabled by the hydraulic fracturing.

Impacts caused by additional oil and gas development enabled by well stimulation (i.e. indirect impacts) account for the majority of environmental impacts associated with hydraulic fracturing. A corollary of this conclusion is that all oil and gas development causes similar impacts whether the oil is produced with well stimulation or not. If indirect impacts caused by additional oil and gas development enabled by hydraulic fracturing cause concern, these concerns in most cases extend to any oil and gas development. As hydraulic fracturing enables only 20% of production in California, only about 20% of any given indirect impact is likely attributable to hydraulically fractured reservoirs.

Without hydraulic fracturing, oil and gas production from certain reservoirs would not be possible. If this oil and gas development did not occur, then the impacts of this development would not occur. Well stimulation is a relatively brief operation done after a well is installed, but oil and gas development goes on for years, involving construction of infrastructure and disruption of the landscape. Operators build roads, ponds, and well pads, and install pumps, field separators, tanks, and treatment systems in reservoirs that are stimulated and in those that are not. Surface spills and subsurface leakage may lead to impacts on groundwater quality as an impact of production. The life of a production well involves production of many millions of gallons of water that must be treated or disposed of properly. Production with or without stimulation can cause emission of pollutants over many years, often in proximity to places where people live, work, and go to school. Whereas the short-term injection of fluids for the purpose of hydraulic fracturing is unlikely to cause a felt or damaging earthquake (a direct impact), the subsurface disposal of millions of gallons of water produced along with oil over the life of a well can present a seismic hazard. The inappropriate disposal of produced water can contaminate protected groundwater, whether this water contains stimulation chemicals or not. All oil and gas development potentially incurs impacts similar to the indirect impacts of hydraulic fracturing.

Recommendation 3.3. Evaluate impacts of production for <u>all</u> oil and gas development, rather than just the portion of production enabled by well stimulation.

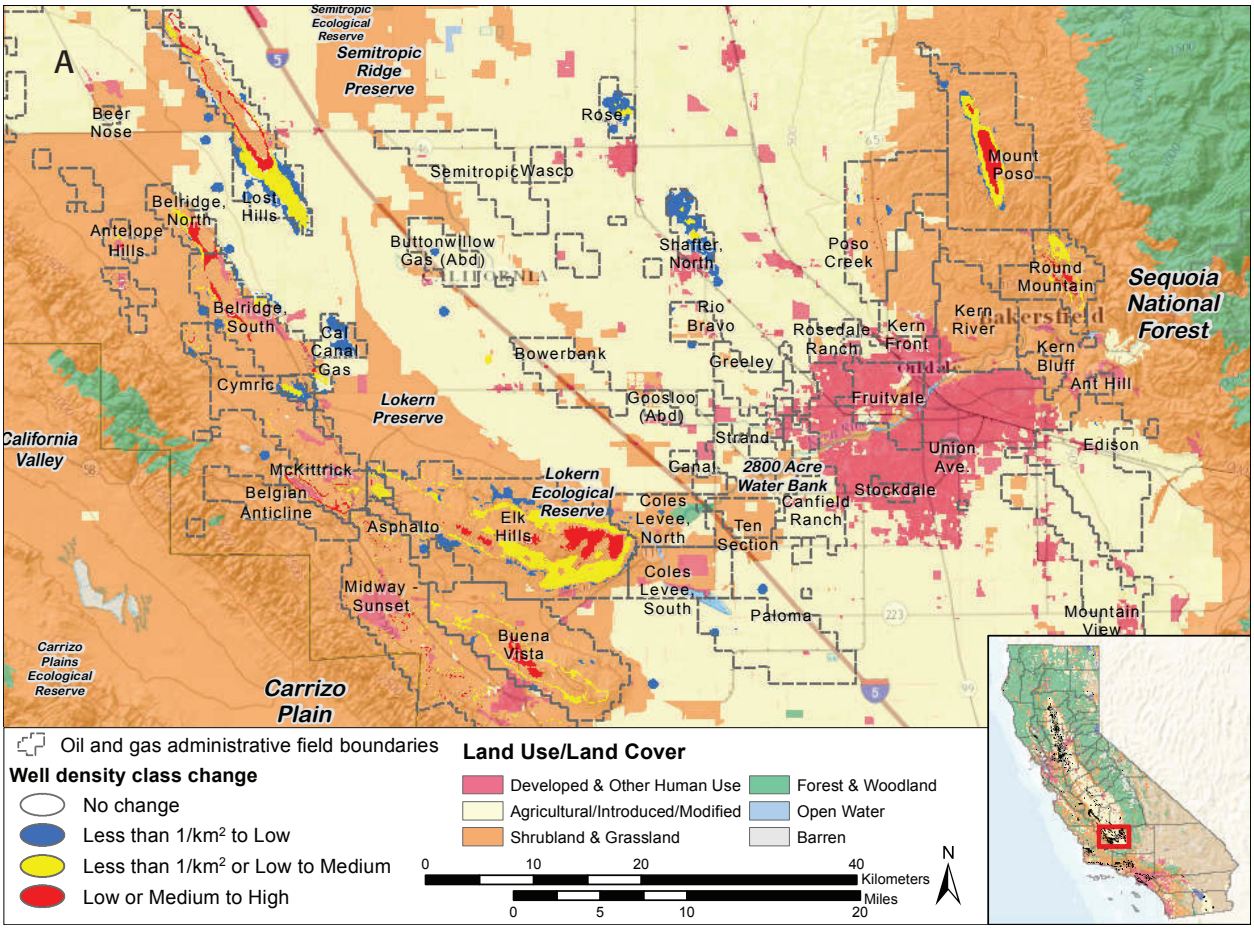
Concern about hydraulic fracturing might cause focus on impacts associated with production from fractured wells, but concern about these indirect impacts should lead to study of all types of oil and gas production, not just production enabled by hydraulic fracturing. Agencies with jurisdiction should evaluate impacts of concern for all oil and gas development, rather than just the portion of development enabled by well stimulation. As appropriate, many of the rules and regulations aimed at mitigating indirect impacts of hydraulic fracturing and acid stimulation should also be applied to all oil and gas wells (Volume II, Chapter 6).

Conclusion 3.4. Oil and gas development causes habitat loss and fragmentation.

Any oil and gas development, including that enabled by hydraulic fracturing, can cause habitat loss and fragmentation. The location of hydraulic fracturing-enabled development coincides with ecologically sensitive areas in Kern and Ventura Counties.

The impact to habitat for native wildlife and vegetation caused by increases in well density depends on the background land use. Some California oil and gas fields are already so densely filled with well pads that other human land uses and native species habitat cannot coexist. Other oil and gas fields have relatively sparse infrastructure interspersed with cities, farms, and natural habitat. The impact caused by increases in well density depends on the background land use. Oil wells installed into agricultural land (such as Rose and Shafter oil fields), or urban areas such as Los Angeles, create only minor impacts to native species. Increases in well density and habitat disturbance from well pads, roads, and facilities cause substantial loss and fragmentation of valuable habitat in those oil and gas fields inhabited by native wildlife and vegetation.

Elk Hills, Mt. Poso, Buena Vista, and Lost Hills fields in Kern County and the Sespe, Ojai, and Ventura fields in Ventura County host substantial amounts of hydraulic fracturing-enabled development as well as rare habitat types and associated endangered species. Portions of oil fields in Kern County are essential to support resident populations of rare species and serve as corridors for maintaining connectivity between remaining areas of natural habitat (including protected areas), and these are vulnerable to expanded production (Figure 1.3-1).


A
Semitropic Ecological Reserve
Semitropic Ridge Preserve
Beer Nose
Rose
Semitropic Wasco
Mount Poso
Belridge, North
Lost Hills
Antelope Hills
Buttonwillow Gas (Abd)
Shafter, North
Poso Creek
Round Mountain
Sequoia National Forest
Belridge, South
Cal Canal Gas
Rio Bravo
Rosedale Ranch
Kern Front
Kern River
Kern Bluff
Bowerbank
Greeley
Cymric
Lokern Preserve
Goosloo (Abd)
Fruitvale
Ant Hill
California Valley
Strand
Union Ave.
Edison
Canal
2800 Acre Water Bank
Stockdale
McKittrick
Belgian Anticline
Lokern Ecological Reserve
Canfield Ranch
Coles Levee, North
Ten Section
Asphalto
Elk Hills
Coles Levee, South
Midway - Sunset
Paloma
Mountain View
Buena Vista
Carrizo Plains Ecological Reserve
Carrizo Plain
Oil and gas administrative field boundaries
Well density class change
No change
Less than 1/km² to Low
Less than 1/km² or Low to Medium
Low or Medium to High
Land Use/Land Cover
Developed & Other Human Use
Agricultural/Introduced/Modified
Shrubland & Grassland
Forest & Woodland
Open Water
Barren
0 10 20 40 Kilometers
0 5 10 20 Miles
N

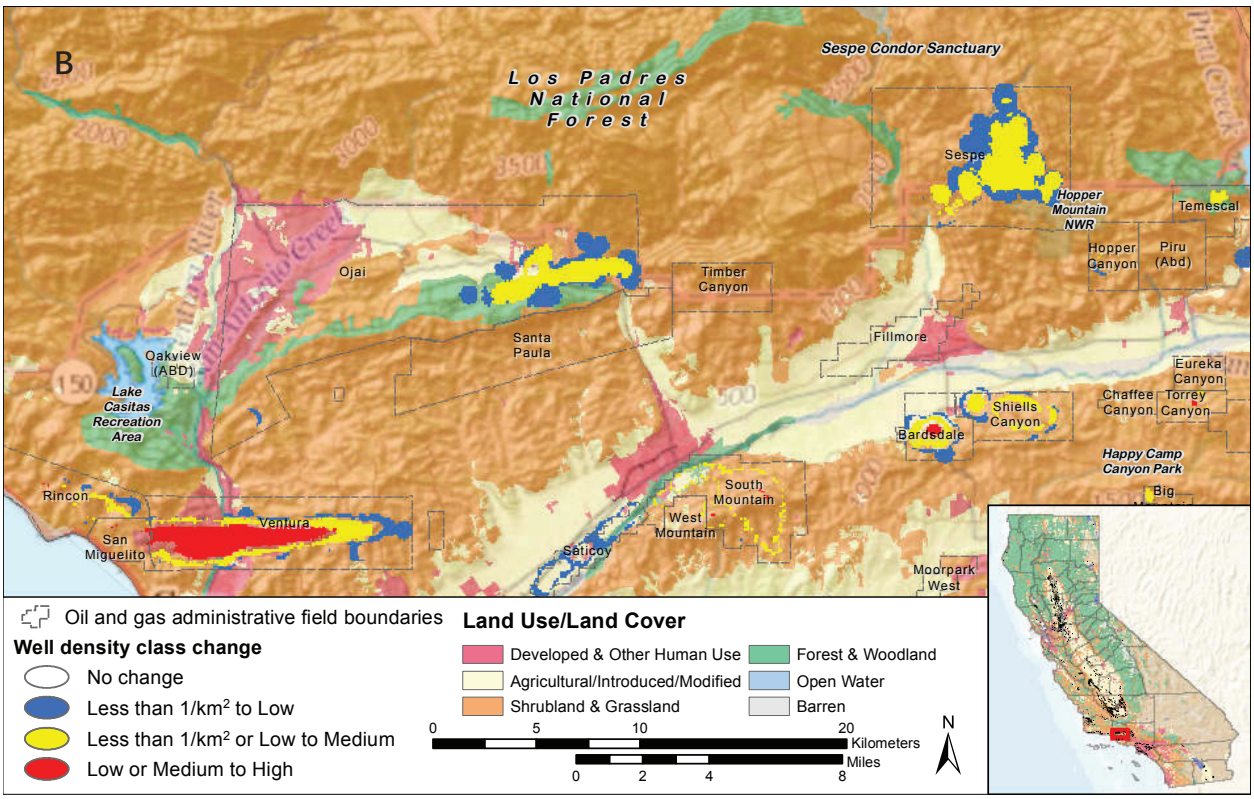

B
Los Padres National Forest
Sespe Condor Sanctuary
Sespe
Hopper Mountain NWR
Temescal
Hopper Canyon
Piru (Abd)
Timber Canyon
Ojai
Santa Paula
Fillmore
Oakview (ABD)
Lake Casitas Recreation Area
Eureka Canyon
Chaffee Canyon
Torrey Canyon
Shiells Canyon
Bardsdale
Happy Camp Canyon Park
Big
Rincon
South Mountain
West Mountain
Ventura
San Miguelito
Seticoy
Moorpark West
Oil and gas administrative field boundaries
Well density class change
No change
Less than 1/km² to Low
Less than 1/km² or Low to Medium
Low or Medium to High
Land Use/Land Cover
Developed & Other Human Use
Agricultural/Introduced/Modified
Shrubland & Grassland
Forest & Woodland
Open Water
Barren
0 5 10 20 Kilometers
0 2 4 8 Miles
N

Figure 1.3-1. Maps of (a) Kern and (b) Ventura Counties showing the increase in well density attributable to hydraulic fracturing-enabled development and land use/land cover between 1977 and 2014. We compared two scenarios for well density in California: actual well density, with all wells present; and a theoretical well density, without hydraulically fractured wells. Foreground colors show areas that have a higher well density with hydraulic fracturing-enabled production. Background shading shows land use/land cover. Kern and Ventura Counties each had oil fields where a substantial proportion of wells were enabled by hydraulic fracturing and where the underlying land use was undeveloped, open land (figure modified from Volume II, Chapter 5).

Ecologically sensitive areas require the conservation of habitat to compensate for new oil and gas development. Currently, no regional planning strategy exists to coordinate habitat conservation efforts in a manner that would ensure continued viable populations of rare species. While possible to compensate only for habitat loss caused by hydraulic fracturing-enabled development, a more logical approach would account for habitat loss from oil and gas production as a whole. Maintaining habitat connectivity in the southwestern San Joaquin will likely require slowing or halting increases in well pad density in dispersal corridors. This type of planning, such as the Kern County Valley Floor Habitat Restoration Plan, has not succeeded in the past, but a renewed effort would safeguard the survival of threatened and endangered species.

> **Recommendation 3.4. Minimize habitat loss and fragmentation in oil and gas producing regions.**
>
> *Enact regional plans to conserve essential habitat and dispersal corridors for native species in Kern and Ventura Counties. The plans should identify top-priority habitat and restrict development of those areas. The plan should also define and require those practices, such as clustering multiple wells on a pad and using centralized networks of roads and pipes, which will minimize future surface disturbances. A program to set aside compensatory habitat in reserve areas when oil and gas development causes habitat loss and fragmentation should be developed and implemented (Volume II, Chapter 5; Volume III, Chapter 5 [San Joaquin Basin Case Study]).*

1.3.2. Management of Produced Water from Hydraulically Fractured or Acid Stimulated Wells

Large volumes of water of various salinities and qualities get produced along with the oil. Oil reservoirs tend to yield increasing quantities of water over time, and most of California's oil reservoirs have been in production for several decades to over a century. For 2013, more than .48 billion m3 (3 billion barrels) of water came along with some .032 billion m3 (0.2 billion barrels) of oil in California. Operators re-inject some produced water back into the oil and gas reservoirs to help recover more petroleum and mitigate land subsidence. In other cases, farmers use this water for irrigation; often blending treated produced water with higher-quality water to reduce salinity. Disposal or reuse of produced water without proper precautions can cause contamination of groundwater and

more so, if this water contains chemicals from hydraulic fracturing and acid stimulation. Underground injection of produced water can cause earthquakes.

Conclusion 4.1. Produced water disposed of in percolation pits could contain hydraulic fracturing chemicals.

Based on publicly available data, operators disposed of some produced water from stimulated wells in Kern County in percolation pits. The effluent has not been tested to determine if there is a measureable concentration of hydraulic fracturing chemical constituents. If these chemicals were present, the potential impacts to groundwater, human health, wildlife, and vegetation would be extremely difficult to predict, because there are so many possible chemicals, and the environmental profiles of many of them are unmeasured.

A commonly reported disposal method for produced water from stimulated wells in California is by evaporation and percolation in percolation surface impoundments, also referred to as percolation pits, as shown in Figure 1.3-2. Information from 2011 to 2014 indicates that operators dispose of some 40-60% of the produced water from hydraulically fractured wells in percolation pits during the first full month of production after stimulation. The range in estimated proportion stems from uncertainties about which wells were stimulated prior to mandatory reporting. Produced water from these wells may contain hazardous chemicals from hydraulic fracturing treatments, as well as reaction byproducts of those chemicals. We do not know how long hydraulic fracturing chemicals persist in produced water or at what concentrations or how these change in time, which means that hazardous levels of contaminants in produced water disposed into pits cannot be ruled out.

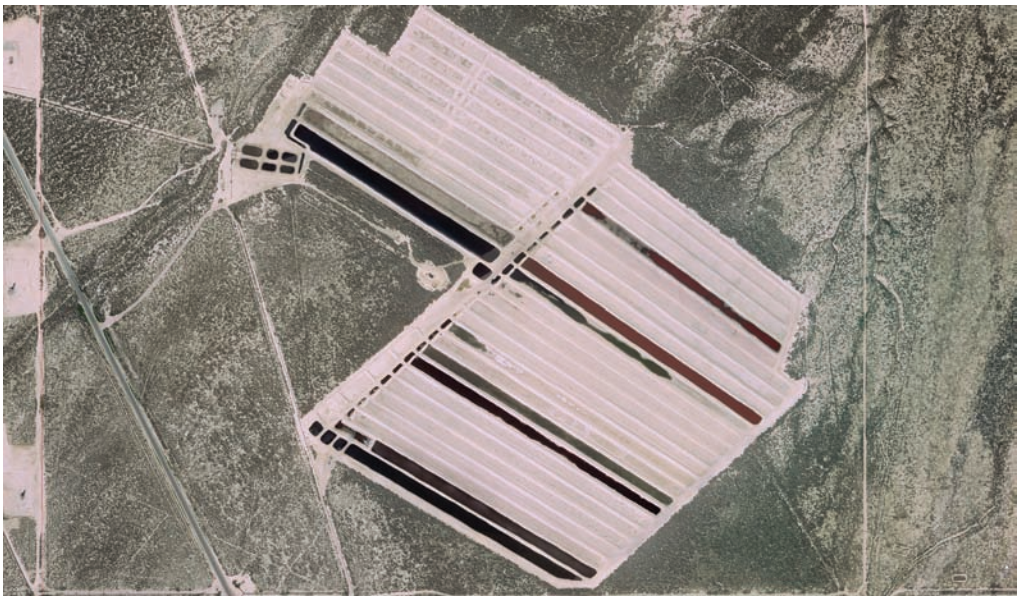


Figure 1.3-2. Percolation pits in Kern County used for produced water disposal (figure modified from Volume II, Chapter 1). Image courtesy of Google Earth.

The primary intent of percolation pits is to percolate water into the ground. This practice provides a potential direct pathway to transport produced water constituents, including returned hydraulic fracturing fluids, into groundwater aquifers. Groundwater contaminated in this way could subsequently intercept rivers, streams, and surface water resources. Contaminated water used by plants (including food crops), humans, fish, and wildlife could introduce contaminants into the food chain. Some states, including Kentucky, Texas and Ohio, have phased out the use of percolation pits for produced water disposal, because their use has demonstrably contaminated groundwater.

Operators have reported disposal of produced water in percolation pits in several California counties (e.g., Fresno, Monterey, and Tulare counties). However, records from 2011 to mid-2014 show that percolation pits received produced water from hydraulically fractured wells only in Kern County. Specifically, wells in the Elk Hills, South Belridge, North Belridge, Lost Hills, and Buena Vista fields were hydraulically fractured, and these fields disposed of produced water to percolation pits in the region under the jurisdiction of the CVRWQCB. An estimated 36% of percolation pits in the Central Valley operate without necessary permits from the CVRWQCB.

The data reported to DOGGR may contain errors on disposition of produced water. For example, DOGGR's production database shows that, during the past few years, one operator discharged produced water to percolation pits at Lost Hills, yet Central Valley Regional Water Quality Control Board (CVRWQCB) ordered the closure of percolation pits at Lost Hills in 2009.[2]

Data collected pursuant to the recent Senate Bill 1281 (SB 1281) will shed light on the disposition of produced water and locations of percolation pits statewide. With the data available as of the writing of this report, we cannot rule out that some produced water from hydraulically fractured wells at other fields went to percolation pits and that this water might have contained chemicals used in hydraulic fracturing. Figure 1.3-3 shows that many of these pits overlie protected groundwater. The pending well stimulation regulations, effective July 1, 2015, disallow fluid produced from a stimulated well from being placed in percolation pits.[3]

2. Order R5-2013-0056, Waste Discharge Requirements for Chevron USA, Inc., Central Valley Regional Water Quality Control Board.

3. Title 14 California Code of Regulations, Section 1786(a)(4)

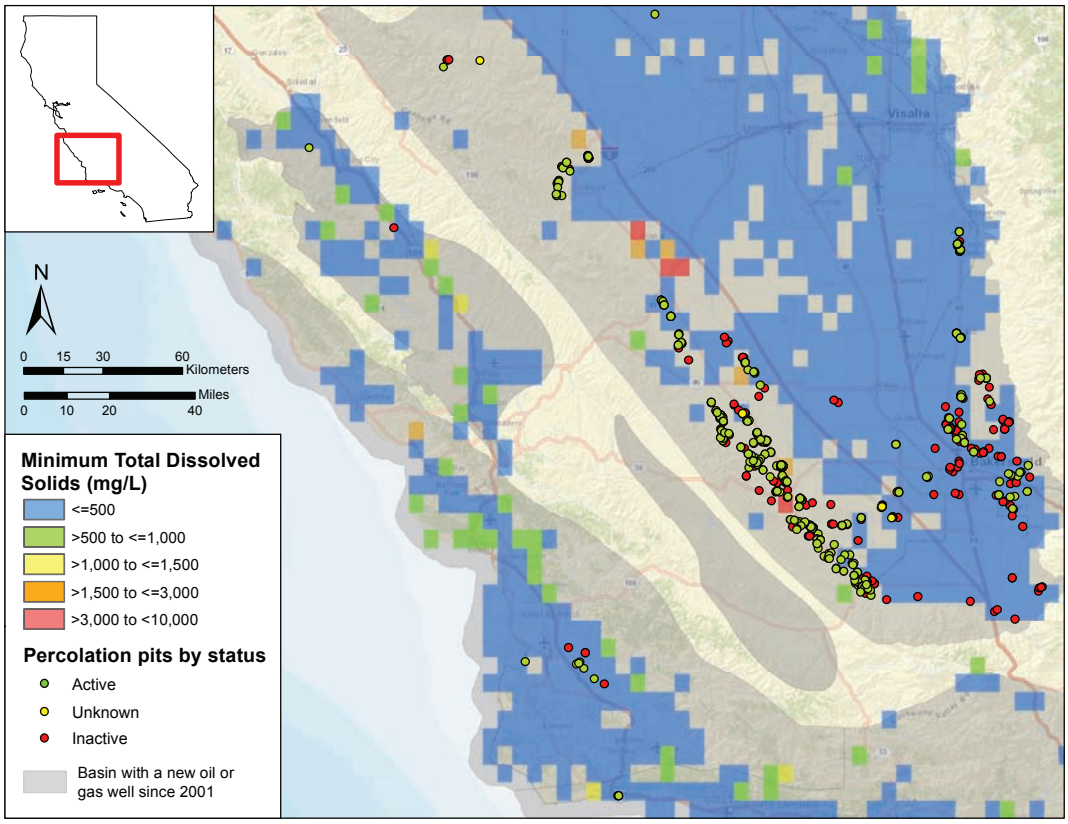


Figure 1.3-3. Location of percolation pits in the Central Valley and Central Coast used for produced water disposal and the location of groundwater of varying quality showing that many percolation pits are located in regions that have potentially protected groundwater shown in color (figure from Volume II, Chapter 2).

Recommendation 4.1. Ensure safe disposal of produced water in percolation pits with appropriate testing and treatment or phase out this practice.

Agencies with jurisdiction should promptly ensure through appropriate testing that the water discharged into percolation pits does not contain hazardous amounts of chemicals related to hydraulic fracturing as well as other phases of oil and gas development. If the presence of hazardous concentrations of chemicals cannot be ruled out, they should phase out the practice of discharging produced water into percolation pits. Agencies should investigate any legacy effects of discharging produced waters into percolation pits including the potential effects of stimulation fluids (Volume II, Chapter 2; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Studies]).

Conclusion 4.2. The chemistry of produced water from hydraulically fractured or acid stimulated wells has not been measured.

Chemicals used in each hydraulic fracturing operation can react with each other and react with the rocks and fluids of the oil and gas reservoirs. When a well is stimulated with acid, the reaction of the acid with the rock minerals, petroleum, and other injected chemicals can release contaminants of concern in the oil reservoirs, such as metals or fluoride ions that have not been characterized or quantified. These contaminants may be present in recovered and produced water.

An average of about 25 different chemicals are used in each hydraulic fracturing operation. As discussed in Conclusion 3.2, some of these can be quite hazardous alone and chemical reactions can results in new constituents. Acids used in well treatments quickly react with rock minerals and become neutralized. But acids can dissolve and mobilize naturally occurring heavy metals and other pollutants in the oil-bearing formation. Neutralized hydrofluoric acid can release toxic fluoride ions into groundwater. Assessment of the environmental risks posed by hydraulic fracturing and acid use along with commonly associated chemicals, such as corrosion inhibitors, requires more complete disclosure of chemical use and a better understanding of the chemistry of treatment fluids and produced water returning to the surface. We found no characterization of the chemistry of produced water from wells that have been hydraulically fractured or stimulated with acid.

> **Recommendation 4.2. Evaluate and report produced water chemistry from hydraulically fractured or acid stimulated wells.**
>
> *Evaluate the chemistry of produced water from hydraulically fractured and acid stimulated wells, and the potential consequences of that chemistry for the environment. Determine how this chemistry changes over time. Require reporting of all significant chemical use, including acids, for oil and gas development (Volume II, Chapters 2 and 6).*

Conclusion 4.3. Required testing and treatment of produced water destined for reuse may not detect or remove chemicals associated with hydraulic fracturing and acid stimulation.

Produced water from oil and gas production has potential for beneficial reuse, such as for irrigation or for groundwater recharge. In fields that have applied hydraulic fracturing or acid stimulations, produced water may contain hazardous chemicals and chemical byproducts from well stimulation fluids. Practice in California does not always rule out the beneficial reuse of produced water from wells that have been hydraulically fractured or stimulated with acid. The required testing may not detect these chemicals, and the treatment required prior to reuse necessarily may not remove hydraulic fracturing chemicals.

Growing pressure on water resources in the state means more interest in using produced water for a range of beneficial purposes, such as groundwater recharge, wildlife habitat, surface waterways, irrigation, etc. Produced water could become a significant resource for California.

However, produced water from wells that have been hydraulically fractured may contain hazardous chemicals and chemical by-products. Our study found only one oil field where both hydraulic fracturing occurs and farmers use the produced water for irrigation. In the Kern River field in the San Joaquin Basin, hydraulic fracturing operations occasionally occur, and a fraction of the produced water goes to irrigation (for example, Figure 1.3-4). But we did not find policies or procedures that would necessarily exclude produced water from hydraulically fractured wells from use in irrigation.



Figure 1.3-4. Produced water used for irrigation in Cawelo water district. Photo credit: Lauren Sommer/KQED (figure from Volume II, Chapter 1).

The regional water quality control boards require testing and treatment of produced water prior to use for irrigation, but the testing does not include hydraulic fracturing chemicals, and required treatment would not necessarily remove hazardous stimulation fluid constituents if they were present. Regional water-quality control boards have also established monitoring requirements for each instance where produced water is applied to irrigated lands; however, these requirements do not include monitoring for constituents specific to, or indicative of, hydraulic fracturing.

Safe reuse of produced water that may contain stimulation chemicals requires appropriate testing and treatment protocols. These protocols should match the level of testing and treatment to the water-quality objectives of the beneficial reuse. However, designing the

appropriate testing and treatment protocols to ensure safe reuse of waters contaminated with stimulation chemicals presents significant challenges, because so many different chemicals could be present, and the safe concentration limits for many of them have not been established. Hydraulic fracturing chemicals may be present in extremely small concentrations that present negligible risk, but this has not been confirmed.

Limiting hazardous chemical use as described in Recommendation 3.2 would also help to limit issues with reuse. Disallowing the reuse of produced water from hydraulically fractured wells would also solve this problem, especially in the first years of production. This water could be tested over time to determine if hazardous levels of hydraulic fracturing chemicals remain before transitioning this waste stream to beneficial use.

> **Recommendation 4.3. Protect irrigation water from contamination by hydraulic fracturing chemicals and stimulation reaction products.**
>
> *Agencies of jurisdiction should clarify that produced water from hydraulically fractured wells cannot be reused for purposes such as irrigation that could negatively impact the environment, human health, wildlife and vegetation. This ban should continue until or unless testing the produced water specifically for hydraulic fracturing chemicals and breakdown products shows non-hazardous concentrations, or required water treatment reduces concentrations to non-hazardous levels (Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).*

Conclusion 4.4. Injection wells currently under review for inappropriate disposal into protected aquifers may have received water containing chemicals from hydraulic fracturing.

DOGGR is currently reviewing injection wells in the San Joaquin Valley for inappropriate disposal of oil and gas wastewaters into protected groundwater. The wastewaters injected into some of these wells likely included stimulation chemicals because hydraulic fracturing occurs nearby.

In 2014, DOGGR began to evaluate injection wells in California used to dispose of oil field wastewater. DOGGR found that some wells inappropriately allowed injection of wastewater into protected groundwater and subsequently shut them down. DOGGR's ongoing investigation will review many more wells to determine if they are injecting into aquifers that should be protected.

Figure 1.3-5 is a map of the Elks Hills field in the San Joaquin Basin showing one example where hydraulically fractured wells exist near active water disposal wells. The DOGGR review includes almost every disposal well in this field for possible inappropriate injection into protected water. Some of the produced water likely came from nearby production wells that were hydraulically fractured. Consequently, the injected wastewater possibly contained stimulation chemicals at some unknown concentration.

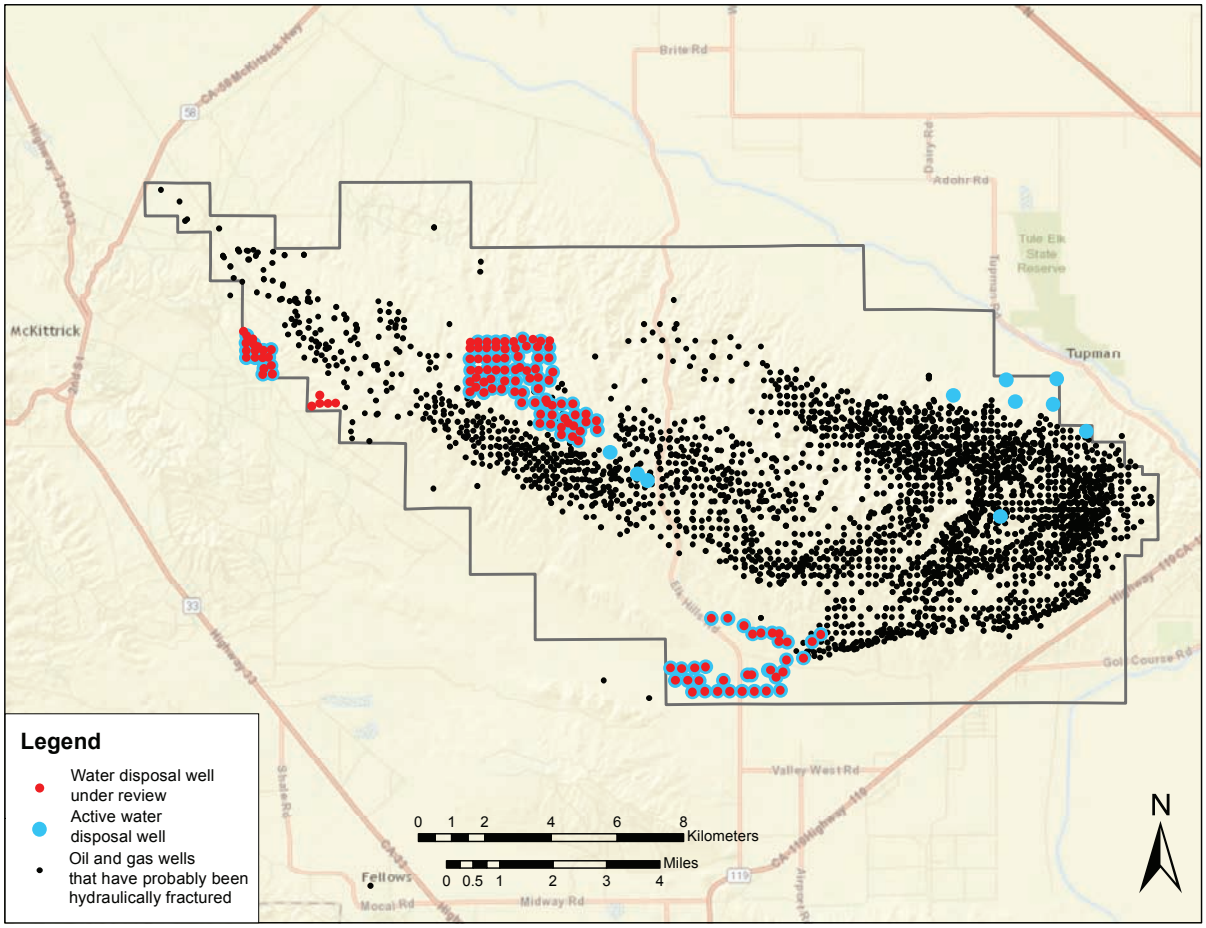


Figure 1.3-5. A map of the Elk Hills field in the San Joaquin Basin showing the location of wells that have probably been hydraulically fractured (black dots). Blue dots are the location of active water disposal wells, and blue dots with a red center are the location of disposal wells under review for possibly injecting into groundwater that should be protected (figure from Volume II, Chapter 1).

Recommendation 4.4. In the ongoing investigation of inappropriate disposal of wastewater into protected aquifers, recognize that hydraulic fracturing chemicals may have been present in the wastewater.

In the ongoing process of reviewing, analyzing, and remediating the potential impacts of wastewater injection into protected groundwater, agencies of jurisdiction should include the possibility that hydraulic fracturing chemicals may have been present in these wastewaters (Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).

Conclusion 4.5. Disposal of wastewater by underground injection has caused earthquakes elsewhere.

Fluid injected in the process of hydraulic fracturing will not likely cause earthquakes of concern. In contrast, disposal of produced water by underground injection could cause felt or damaging earthquakes. To date, there have been no reported cases of induced seismicity associated with produced water injection in California. However, it can be very difficult to distinguish California's frequent natural earthquakes from those possibly caused by water injection into the subsurface.

Hydraulic fracturing causes a pressure increase for a short amount of time and affects relatively small volumes of rock. For this reason, hydraulic fracturing has a small likelihood of producing felt (*i.e.*, sensed), let alone damaging, earthquakes. In California, only one small earthquake (which occurred in 1991) has been linked to hydraulic fracturing to date (Volume II, Chapter 4).

Disposal into deep injection wells of water produced from oil and gas operations has caused felt seismic events in several states, but there have been no reported cases of induced seismicity associated with wastewater injection in California. The volume of produced water destined for underground injection could increase for a number of reasons, and disposal of increased volumes by injection underground could increase seismic hazards.

California has frequent naturally occurring earthquakes—so many that seismologists have a hard time determining if any of these earthquakes were actually induced by fluid injection. In areas like Kansas that do not have frequent earthquakes, it is much easier to find correlations between an earthquake and human activity. In the future, the amount of fluid requiring underground injection in California could increase locally due to expanded production or a change in disposal practice. Such change in practice might incur an unacceptable seismic risk, but understanding this possible risk requires a better understanding of the current correlation between injection and earthquakes, if any.

California also has many geologic faults. Figure 1.3-6 shows a map of California earthquake epicenters, the location of wastewater disposal wells active since 1981 and faults in the United States Geological Survey (USGS) database in central and southern California. Across all six oil-producing basins, over 1,000 wells are located within 2.5 km (1.5 miles) of a mapped active fault, and more than 150 within 200 m (650 ft).

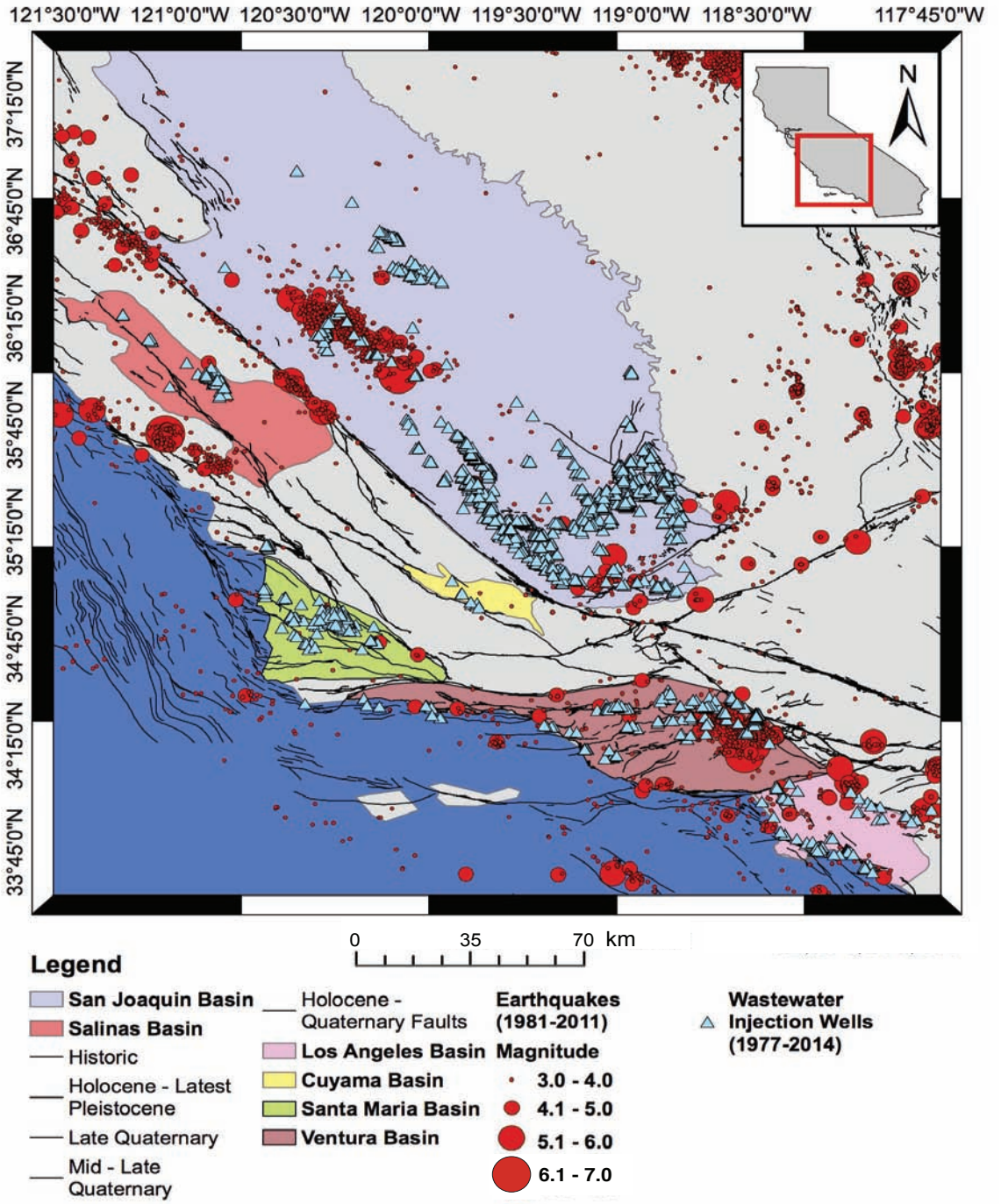


Figure 1.3-6. High-precision locations for earthquakes M≥3 in central and southern California during the period 1981-2011, and active and previously active water disposal wells from DOGGR (figure from Volume II, Chapter 4).

A systematic regional-scale analysis of earthquake occurrence in relation to water injection would help identify if induced seismicity exists in California. This study should include statistical characterizations and geomechanical analysis for induced seismicity and will require more detailed data than that currently reported by industry on injection depth, variations in fluid injection rate, and pressure over time. Currently, operators report the volume of injected water and wellhead pressures only as monthly averages. Analysts will need to know more about exactly when, how, how much, where injection occurred to identify a potential relationship between earthquakes and injection patterns. A systematic study will also require geophysical characterization of oil field test sites, detailed seismic monitoring, and modeling of the subsurface pressure changes produced by injection in the vicinity of the well.

The state could likely manage and mitigate potential induced seismicity, by adopting protocols to modify an injection operation when and if seismic activity is detected. The protocol could require reductions in injection flow rate and pressure, and shutting down the well altogether if the risk of an earthquake rises above some threshold. Currently, ad hoc protocols exist for this purpose. Better protocols would require monitoring the reservoir and local seismic activity, and formal calculation of the probability of inducing earthquakes of concern.

Recommendation 4.5. Determine if there is a relationship between wastewater injection and earthquakes in California.

Conduct a comprehensive multi-year study to determine if there is a relationship between oil and gas-related fluid injection and any of California's numerous earthquakes. In parallel, develop and apply protocols for monitoring, analyzing, and managing produced water injection operations to mitigate the risk of induced seismicity. Investigate whether future changes in disposal volumes or injection depth could affect potential for induced seismicity (Volume II, Chapter 4).

Conclusion 4.6. Changing the method of wastewater disposal will incur tradeoffs in potential impacts.

Based on publicly available data, operators dispose of much of the produced water from stimulated wells in percolation pits (evaporation-percolation ponds), about a quarter by underground injection (in Class II wells), and less than one percent to surface bodies of water. Changing the method of produced water disposal could decrease some potential impacts while increasing others.

Figure 1.3-7 shows the results of an analysis of disposal methods of produced water from known stimulated wells in the first full month after stimulation during the period from 2011 to 2014. As much as 60% of the water was sent to percolation pits, also known as evaporation-percolation ponds, as discussed in Conclusion 4.1 Second to this, produced

water from stimulated wells was injected into Class II wells for disposal or enhanced oil recovery. With proper regulation, siting, construction, and maintenance, subsurface injection is less likely to result in groundwater contamination than disposal in percolation pits.

However, increasing injection volumes could increase the risk of induced seismicity, discussed in Conclusion 4.5. Also, concerns have recently emerged about whether California's Class II underground injection control (UIC) program provides adequate protection for underground sources of drinking water (USDWs), as discussed in Conclusion 4.4, USDWs are defined as groundwater aquifers that currently or could one day supply water for human consumption. The least common method of dealing with wastewater, disposal to surface bodies of water, can, for example, augment stream flows, but requires careful testing and treatment to ensure the water is safe, especially if stimulation chemicals could be present.

The DOGGR monthly production data either do not specify the disposal method or report as "other" for 17% of the produced water from known stimulated wells. This reporting category could include subsurface injection, disposal to a surface body of water, sewer disposal, or water not disposed of but reused for irrigation or another beneficial purpose, as described in Conclusion 4.3.

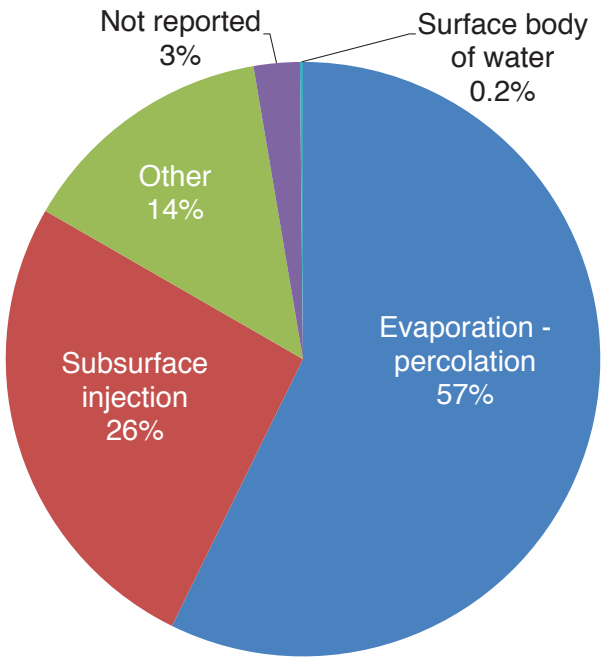


Figure 1.3-7. Disposal method for produced water from hydraulically fractured wells during the first full month after stimulation for the time period 2011-2014 based on data from DOGGR monthly production database. Note: Subsurface injection includes any injection into Class II wells, which include disposal wells as well as enhanced recovery wells used for water flooding and steam flooding (figure from Volume II, Chapter 2).

Changing the method of produced water disposal or reuse will incur tradeoffs. Any attempt to reduce one disposal method must consider the likely outcome that other disposal methods will increase. For example, eliminating disposal in evaporation–percolation pits can lead to an increase in other disposal methods to make up the difference. In particular, closure of percolation pits or injection wells found to be contaminating protected aquifers would increase the use of other disposal methods, and this will require careful planning and management on a regional basis.

Recommendation 4.6. Evaluate tradeoffs in wastewater disposal practices.

As California moves to change disposal practices, for example by phasing out percolation pits or stopping injection into protected aquifers, agencies with jurisdiction should assess the consequences of modifying or increasing disposal via other methods (Volume II, Chapter 2; Volume II, Chapter 4).

1.3.3. Protections to Avoid Groundwater Contamination by Hydraulic Fracturing

Hydraulic fracturing operations could contaminate groundwater through a variety of pathways. We found no documented instances of hydraulic fracturing or acid stimulations directly causing groundwater contamination in California. However, we did find that fracturing in California tends to be in shallow wells and in mature reservoirs that have many existing boreholes. These practices warrant more attention to ensure that they have not and will not cause contamination.

Conclusion 5.1. Shallow fracturing raises concerns about potential groundwater contamination.

In California, about three quarters of all hydraulic fracturing operations take place in shallow wells less than 600 m (2,000 ft) deep. In a few places, protected aquifers exist above such shallow fracturing operations, and this presents an inherent risk that hydraulic fractures could accidentally connect to the drinking water aquifers and contaminate them or provide a pathway for water to enter the oil reservoir. Groundwater monitoring alone may not necessarily detect groundwater contamination from hydraulic fractures. Shallow hydraulic fracturing conducted near protected groundwater resources warrants special requirements and plans for design control, monitoring, reporting, and corrective action.

Hydraulic fractures produced in deep formations far beneath protected groundwater are very unlikely to propagate far enough upwards to intersect an aquifer. Studies performed for high-volume hydraulic fracturing elsewhere in the country have shown that hydraulic fractures have propagated no further than 600 m (2,000 ft) vertically, so hydraulic fracturing conducted many thousands of feet below an aquifer is not expected to reach a protected aquifer far above. In California, however, and particularly in the San Joaquin Basin, most hydraulic fracturing occurs in relatively shallow reservoirs, where protected groundwater might be found within a few hundred meters (Figure 1.3-8). A few instances

of shallow fracturing have also been reported in the Los Angeles Basin (Figure 1.3-9), but overall much less than the San Joaquin Basin. No cases of contamination have yet been reported, but there has been little to no systematic monitoring of aquifers in the vicinity of oil production sites.

Shallow hydraulic fracturing presents a higher risk of groundwater contamination, which groundwater monitoring may not detect. This situation warrants additional scrutiny. Operations with shallow fracturing near protected groundwater could be disallowed or be subject to additional requirements regarding design, control, monitoring, reporting, and corrective action, including: (1) pre-project monitoring to establish a base-line of chemical concentrations, (2) detailed prediction of expected fracturing characteristics prior to starting the operation, (3) definition of isolation between expected fractures and protected groundwater, providing a sufficient safety margin with proper weighting of subsurface uncertainties, (4) targeted monitoring of the fracturing operation to watch for and react to evidence (e.g., anomalous pressure transients, microseismic signals) indicative of fractures growing beyond their designed extent, (5) monitoring groundwater to detect leaks, (6) timely reporting of the measured or inferred fracture characteristics confirming whether or not the fractures have actually intersected or come close to intersecting groundwater, (7) preparing corrective action and mitigation plans in case anomalous behavior is observed or contamination is detected, and (8) adaption of groundwater monitoring plans to improve the monitoring system and specifically look for contamination in close proximity to possible fracture extensions into groundwater.

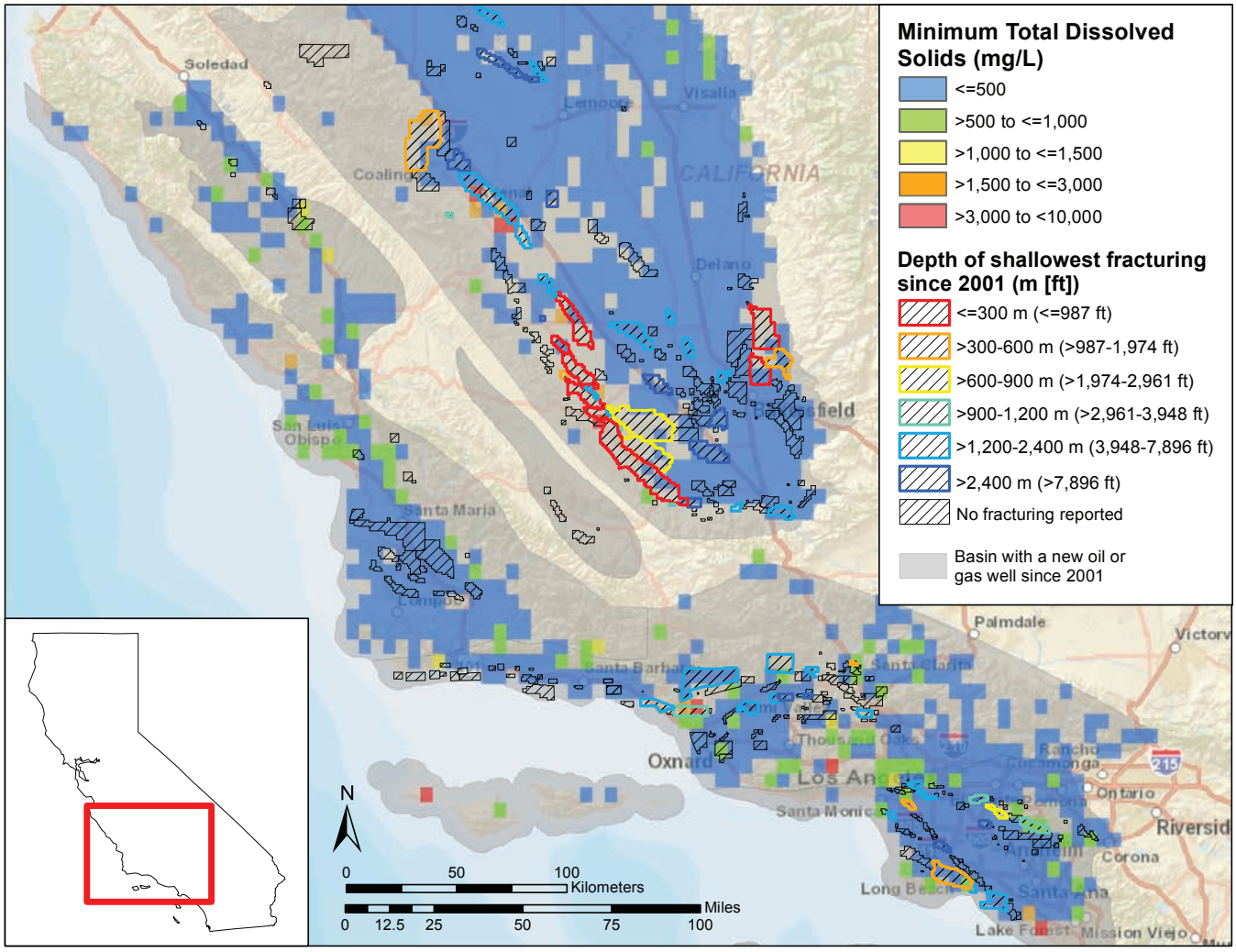


Figure 1.3-8. Shallow fracturing locations and groundwater quality in the San Joaquin and Los Angeles Basins. Some high quality water exists in fields that have shallow fractured wells (figure from Volume II, Chapter 2).

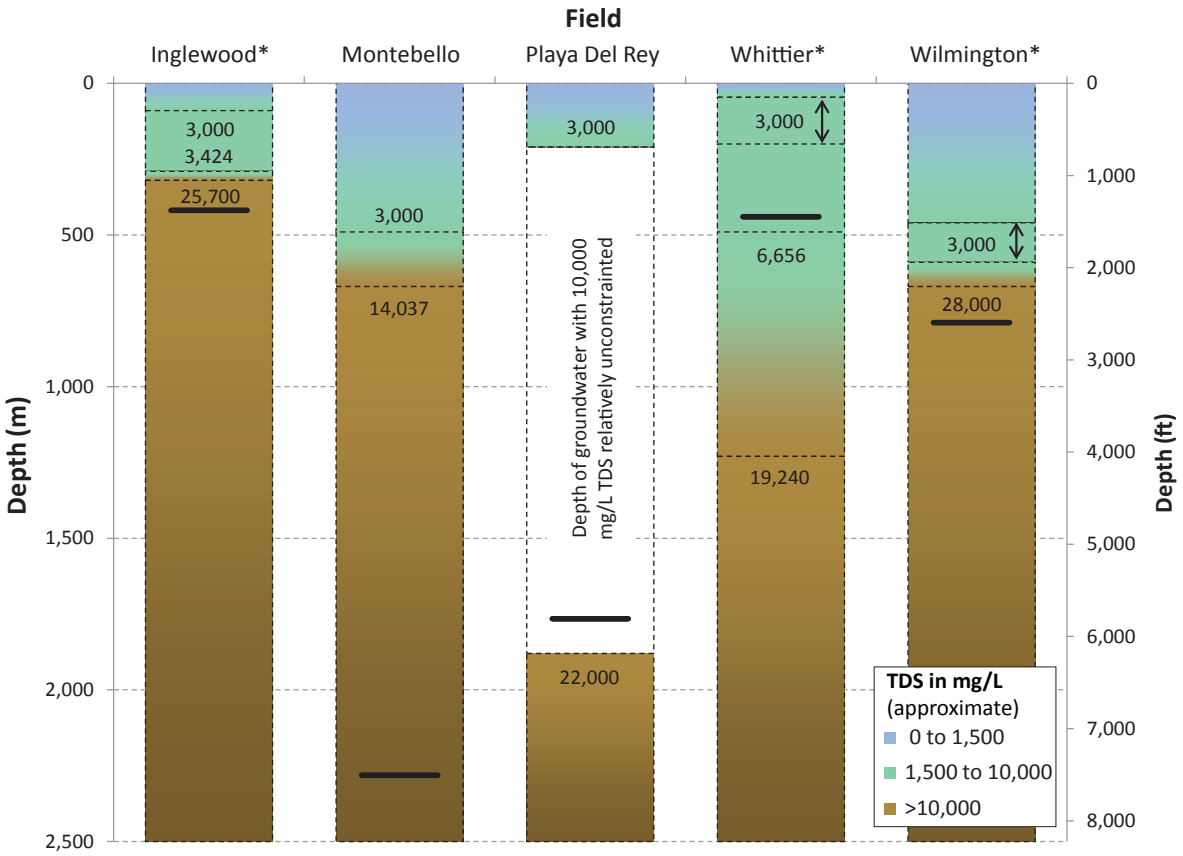


Figure 1.3-9. Depths of groundwater total dissolved solids (TDS) in mg/L in five oil fields in the Los Angeles Basin. The numbers indicate specific TDS data and the colors represent approximate interpolation. The depth of 3,000 mg/L TDS is labeled on all five fields. Blue (<3,000 mg/L) and aqua (between 3,000 mg/L and 10,000 mg/L) colors represent protected groundwater. Depth of 10,000 mg/L TDS is uncertain, but it is estimated to fall in the range where aqua transitions to brown. The heavy black horizontal line indicates the shallowest hydraulically fractured well interval in each field. (Asterisks denote the fields of most concern for the proximity of hydraulic fracturing to groundwater with less than 10,000 mg/L TDS.) (figure from Volume III, Chapter 4 [Los Angeles Basin Case Study]).

The potential for shallow hydraulic fractures to intercept protected groundwater requires both knowing the location and quality of nearby groundwater and accurate information about the extent of the hydraulic fractures. Maps of the vertical depth of protected groundwater with less than 10,000 mg/L TDS for California oil producing regions do not yet exist. Analysis and field verification could identify typical hydraulic fracture geometries; this would help determine the probability of fractures extending into groundwater aquifers. Finally, detection of potential contamination and planning of mitigation measures requires integrated site-specific and regional groundwater monitoring programs.

The pending SB 4 well stimulation regulations, effective July 1, 2015, require operators to design fracturing operations so that the fractures avoid protected water, and to implement appropriate characterization and groundwater monitoring near hydraulic fracturing operations. However, groundwater monitoring alone does not ensure protection of water, nor will it necessarily detect contamination should it occur. The path followed by contamination underground can be hard to predict, and may bypass a monitoring well. Groundwater monitoring can give false negative results in these cases,[4] and does nothing to stop contamination from occurring in any case.

Recommendation 5.1. Protect groundwater from shallow hydraulic fracturing operations.

Agencies with jurisdiction should act promptly to locate and catalog the quality of groundwater throughout the oil-producing regions. Operators proposing to use hydraulic fracturing operation near protected groundwater resources should be required to provide adequate assurance that the expected fractures will not extend into these aquifers and cause contamination. If the operator cannot demonstrate the safety of the operation with reasonable assurance, agencies with jurisdiction should either deny the permit, or develop protocols for increased monitoring, operational control, reporting, and preparedness (Volume I, Chapter 3; Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).

Conclusion 5.2. Leakage of hydraulic fracturing chemicals could occur through existing wells.

California operators use hydraulic fracturing mainly in reservoirs that have been in production for a long time. Consequently, these reservoirs have a high density of existing wells that could form leakage paths away from the fracture zone to protected groundwater or the ground surface. The pending SB 4 regulations going into effect July 1, 2015 do address concerns about existing wells in the vicinity of well stimulation operations; however, it remains to demonstrate the effectiveness of these regulations in protecting groundwater.

In California, most hydraulic fracturing occurs in old reservoirs where oil and gas has been produced for a long time. Usually this means many other wells (called “offset wells”) have previously been drilled in the vicinity of the operation. Wells constructed to less stringent regulations in the past or degraded since installation may not withstand the high pressures

4. Chemical tracers (non-reactive chemicals that can be detected in small concentrations) can be added to hydraulic fracturing fluids and, if groundwater samples contain these tracers, it is evidence that the stimulation fluid has migrated out of the designed zone. However, the use of tracers does not guarantee that leaks to groundwater will be detected. Groundwater flow can be highly channelized and it can be difficult to place a monitoring well in the right place to intersect a possible plume of contaminant. The use of tracers is good practice, but does not “solve” the problem of detecting contamination.

used in hydraulic fracturing. Thus, in California, as well as in other parts of the country, existing oil and gas wells can provide subsurface conduits for oil-field contamination to reach protected groundwater. Old wells present a risk for any oil and gas development, but the high pressures involved in hydraulic fracturing can increase this risk significantly. California has no recorded incidents of groundwater contamination due to stimulation. But neither have there been attempts to detect such contamination with targeted monitoring, nor studies to determine the extent of compromised wellbore integrity.

Historically, California has required placement of well casings and cement seals to protect groundwater with a salinity less than 3,000 mg/L total dissolved solids (TDS). Now, SB 4 requires more stringent monitoring and protection from degradation of non-exempt groundwater with less than 10,000 mg/L TDS. Consequently, existing wells may not have been built to protect groundwater between 3,000 mg/L and 10,000 mg/L TDS. For instance, there may be no cement seal in place to isolate the zones containing water that is between 3,000 and 10,000 mg/L TDS from deeper zones with water that is higher than 10,000 mg/L TDS.

The new well stimulation regulations going into effect in July 1, 2015 require operators to locate and review any existing well within a zone that is twice as large as the expected fractures. Operators need to design the planned hydraulic fracturing operation to confine hydraulic fracturing fluids and hydrocarbons within the hydrocarbon formation. The pressure buildup at offset wells caused by neighboring hydraulic fracturing operations must remain below a threshold value defined by the regulations.

The new regulations for existing wells are appropriate in concept, but the effectiveness of these requirements will depend on implementation practice. For example: How will operators estimate the extent of the fractures, and how will regulators ensure the reliability of these calculations? Is the safety factor provided by limiting concern to an area equal to twice the extent of the designed fractures adequate? How will regulators assess the integrity of existing wells when information about these wells is incomplete? How will regulators determine the maximum allowed pressure experienced at existing wells? Will the regulators validate the theoretical calculations to predict fracture extent and maximum pressure with field observations?

Recommendation 5.2. Evaluate the effectiveness of hydraulic fracturing regulations designed to protect groundwater from leakage along existing wells.

Within a few years of the new regulations going into effect, DOGGR should conduct or commission an assessment of the regulatory requirements for existing wells near stimulation operations and their effectiveness in protecting groundwater with less than 10,000 TDS from well leakage. This assessment should include comparisons of field observations from hydraulic fracturing sites with the theoretical calculations for stimulation area or well pressure required in the regulations (Volume II, Chapter 2; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Studies]).

1.3.4. Emissions and their Impact on Environmental and Human Health

Gaseous emissions and particulates associated with hydraulic fracturing can arise from the use of fossil fuel in engines, outgassing from fluids, leaks, or proppant, which have potential environmental or health impacts.

Conclusion 6.1. Oil and gas production from hydraulically fractured reservoirs emits less greenhouse gas per barrel of oil than other forms of oil production in California.

Burning fossil fuel to run vehicles, make electricity, and provide heat accounts for the vast majority of California's greenhouse gas emissions. In comparison, publicly available California state emission inventories indicate that oil and gas production operations emit about 4% of California total greenhouse gas emissions. Oil and gas production from hydraulically fractured reservoirs emits less greenhouse gas per barrel of oil than production using steam injection. Oil produced in California using hydraulic fracturing also emits less greenhouse gas per barrel than the average barrel imported to California. If the oil and gas derived from stimulated reservoirs were no longer available, and demand for oil remained constant, the replacement fuel could have larger greenhouse emissions.

Most oil-related greenhouse gas (GHG) emissions in the state come from the consumption of fossil fuels such as gasoline and diesel, not the extraction of oil. According to state emission inventories, GHG emissions from oil and gas production processes equal about four percent of total GHG emissions in California, although some studies conclude these emission inventories may underestimate true emissions. Fields with lighter oil result in low emissions per barrel of crude produced, while fields with heavier oil have higher emissions because of the need for steam injection during production as well as more intensive refining needed to produce useful fuels such as gasoline. Well stimulation generally applies to reservoirs with lighter oil and consequently smaller greenhouse gas burdens per unit of oil. Oil and gas from San Joaquin Basin reservoirs using hydraulic fracturing have a relatively smaller carbon footprint than oil and gas from reservoirs such as those in the Kern River field that use steam flooding (Figure 1.3-10).

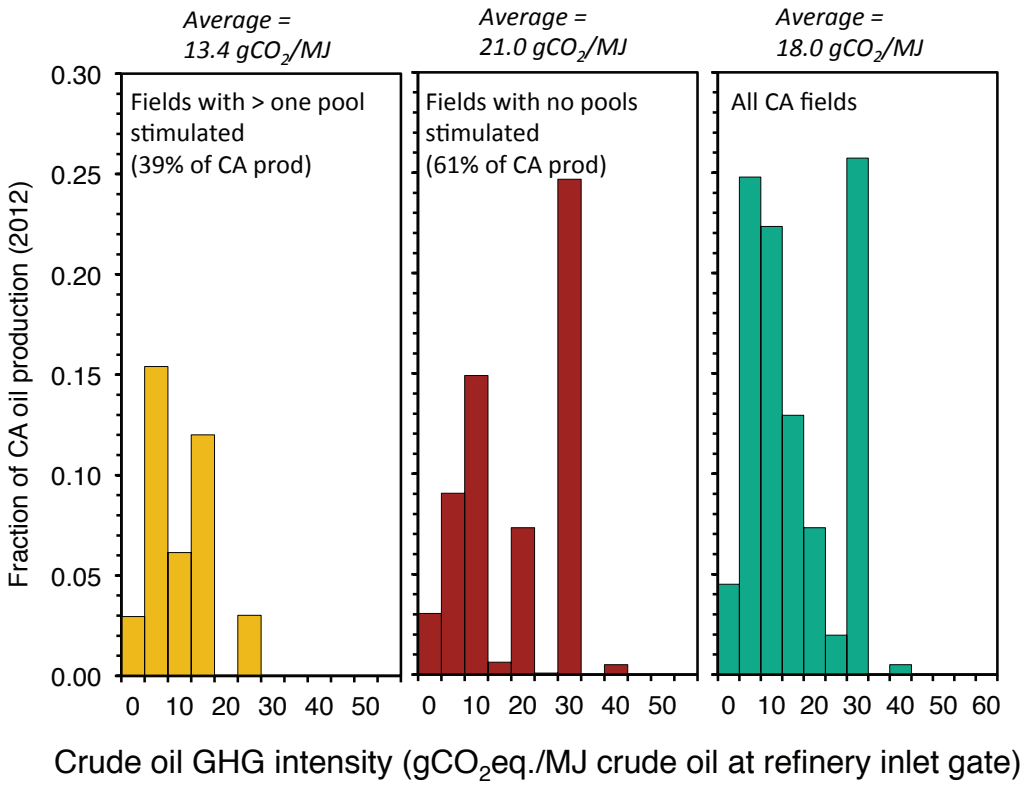


Figure 1.3-10. Distribution of crude oil greenhouse gas intensity for fields containing well-stimulation-enabled pools (left), those that are not stimulated (middle) and all California oilfields (right) (figure from Volume II, Chapter 3).

If well stimulation were disallowed and consumption of oil and gas in California did not decline, more oil and gas would be required from non-stimulated California fields or regions outside of California, possibly with higher emissions per barrel. Consequently, overall greenhouse gas emissions due to production could increase if well stimulation were stopped in California. The net greenhouse gas change associated with the use of hydraulic fracturing requires knowing the carbon footprint of both in-state and out-of-state production, and understanding the scale of impact requires a market-informed life cycle analysis.

Recommendation 6.1. Assess and compare greenhouse gas signatures of different types of oil and gas production in California.

Conduct rigorous market-informed life-cycle analyses of emissions impacts of different oil and gas production to better understand GHG impacts of well stimulation (Volume II, Chapter 3).

Conclusion 6.2. Air pollutants and toxic air emissions[5] from hydraulic fracturing are mostly a small part of total emissions, but pollutants can be concentrated near production wells.

According to publicly available California state emission inventories, oil and gas production in the San Joaquin Valley air district likely accounts for significant emissions of sulfur oxides (SO_x), volatile organic compounds (VOC), and some air toxics, notably hydrogen sulfide (H_2S). In other oil and gas production regions, production as a whole accounts for a small proportion of total emissions. Hydraulic fracturing facilitates about 20% of California production, and so emissions associated with this production also represent about 20% of all emissions from the oil and gas production in California. Even where the proportion of air pollutants and toxic emissions caused directly or indirectly by well simulation is small, atmospheric concentrations of pollutants near production sites can be much larger than basin or regional averages, and could potentially cause health impacts.

In the San Joaquin Valley oil and gas production as a whole accounts for about 30% of sulfur oxides and 8% of anthropogenic volatile organic compound (VOC) emissions. VOCs in turn react with nitrogen oxides (NO_x) to create ozone. Eliminating emissions from oil and gas production would reduce, but not eliminate the difficult air pollution problems in the San Joaquin Valley. Oil and gas facilities also emit significant air toxics in the San Joaquin Valley. They are responsible for a large fraction (>70%) of total hydrogen sulfide emissions and small fractions (2-6%) of total benzene, xylene, hexane, and formaldehyde emissions (Figure 1.3-11). Dust ($PM_{2.5}$ and PM_{10}) is a major air quality concern in the San Joaquin Valley, and agriculture is the dominant source of dust in the region. The amount of dust generated by oil and gas activities (including hydraulic fracturing) is comparatively very small.

5. Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. Criteria air contaminants (CAC), or criteria pollutants, are a set of air pollutants that cause smog, acid rain, and other health hazards.

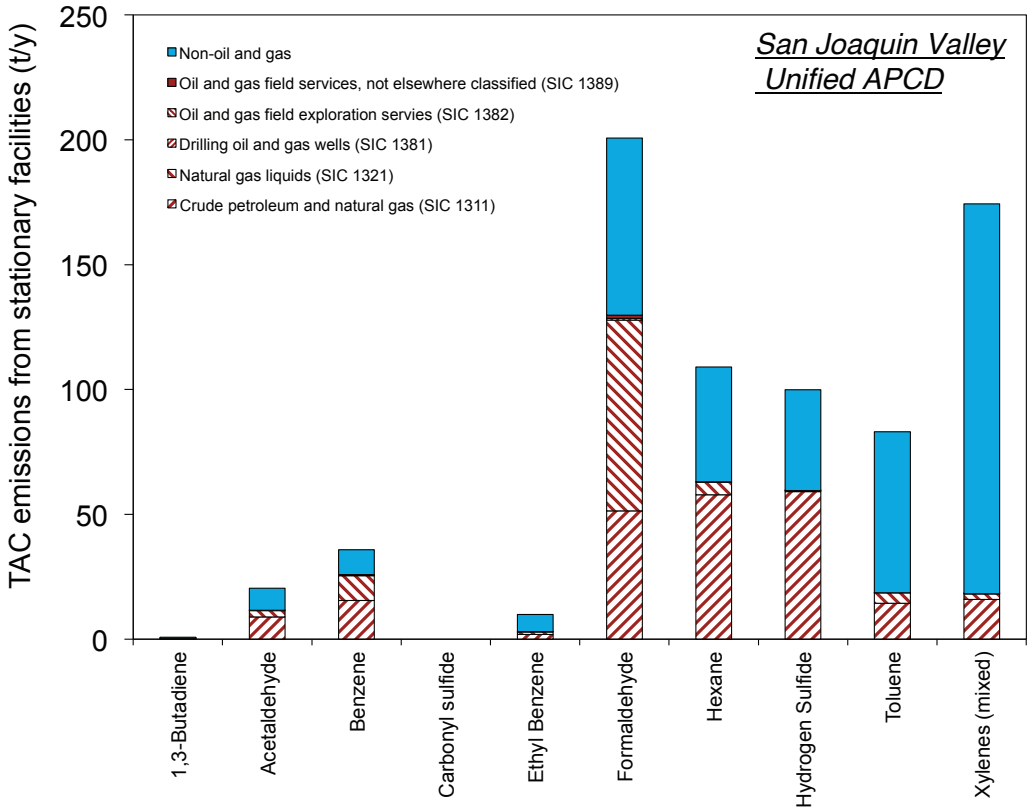


Figure 1.3-11. Summed facility-level toxic air contaminant (TAC) emissions in San Joaquin Valley air district). Facility-level emissions derived from a California Air Resources Board (CARB) facility emissions tool. Total emissions are emissions from all oil and gas facilities in the air district, including gasoline fueling stations (Volume II, Chapter 3) (figure from Volume II, Chapter 3).

In the South Coast Air District (including all of Orange County, the non-desert regions of Los Angeles and Los Angeles County, San Bernardino County, and Riverside County), upstream oil and gas sources represent small proportions (<1%) of criteria air pollutant and toxic air contaminant emissions due to large quantities of emissions from other sources in a highly urbanized area.

> *Produced gas can be emitted during recovery of hydraulic fracturing liquids and therefore be a possible source of direct air emissions from well stimulation. Regulation and control technologies can address these emissions with proper implementation and enforcement. Federal regulations already control emissions during fluid recovery from new gas wells using "green completions," and California is developing similar regulations for oil wells.*

Public data sources provide information about the emissions from all upstream oil and gas production, but do not include information that would allow separating out the

contribution of emissions from hydraulically fractured wells. Because well stimulation facilitates or enables about 20% of California's oil recovery, indirect air impacts from well stimulation are likely on the order of one-fifth of total upstream oil and gas air impacts.

Even if upstream oil and gas operations are not a large part of basin-wide air pollution load, at the scale of counties, cities or neighborhoods, oil and gas development can have larger proportional impacts. Even in regions where well stimulation-related emissions represent a small part of overall emissions, local air toxic concentrations near drilling and production sites may be elevated. This could result in health impacts in densely populated areas such as Los Angeles, where production wells are in close proximity to homes, schools, and businesses. Public datasets do not provide specific enough temporal and spatial data on air toxics emissions that would allow any realistic assessment of these impacts.

Recommendation 6.2. Control toxic air emissions from oil and gas production wells and measure their concentrations near productions wells.

Apply reduced-air-emission completion technologies to production wells, including stimulated wells, to limit direct emissions of air pollutants, as planned. Reassess opportunities for emission controls in general oil and gas operations to limit emissions. Improve specificity of inventories to allow better understanding of oil and gas emissions sources. Conduct studies to improve our understanding of toxics concentrations near stimulated and un-stimulated wells (Volume II, Chapter 3; Volume III, Chapter 4 [Los Angeles Basin Case Study]).

Conclusion 6.3. Emissions concentrated near all oil and gas production could present health hazards to nearby communities in California.

Many of the constituents used in and emitted by oil and gas development can damage health, and place disproportionate risks on sensitive populations, including children, pregnant women, the elderly, and those with pre-existing respiratory and cardiovascular conditions. Health risks near oil and gas wells may be independent of whether wells in production have undergone hydraulic fracturing or not. Consequently, a full understanding of health risks caused by proximity to production wells will require studying all types of productions wells, not just those that have undergone hydraulic fracturing. Oil and gas development poses more elevated health risks when conducted in areas of high population density, such as the Los Angeles Basin, because it results in larger population exposures to toxic air contaminants.

California has large developed oil reserves located in densely populated areas. For example, the Los Angeles Basin reservoirs, which have the highest concentrations of oil in the world, exist within the global megacity of Los Angeles. Approximately half a million people live, and large numbers of schools, elderly facilities, and daycare facilities exist, within one mile of a stimulated well, and many more live near oil and gas development of all types (Figure 1.3-12). The closer citizens are to these industrial facilities, the higher their potential exposure to toxic air emissions and higher risk of associated health effects. Production enabled by well stimulation accounts for a fraction of these emissions.

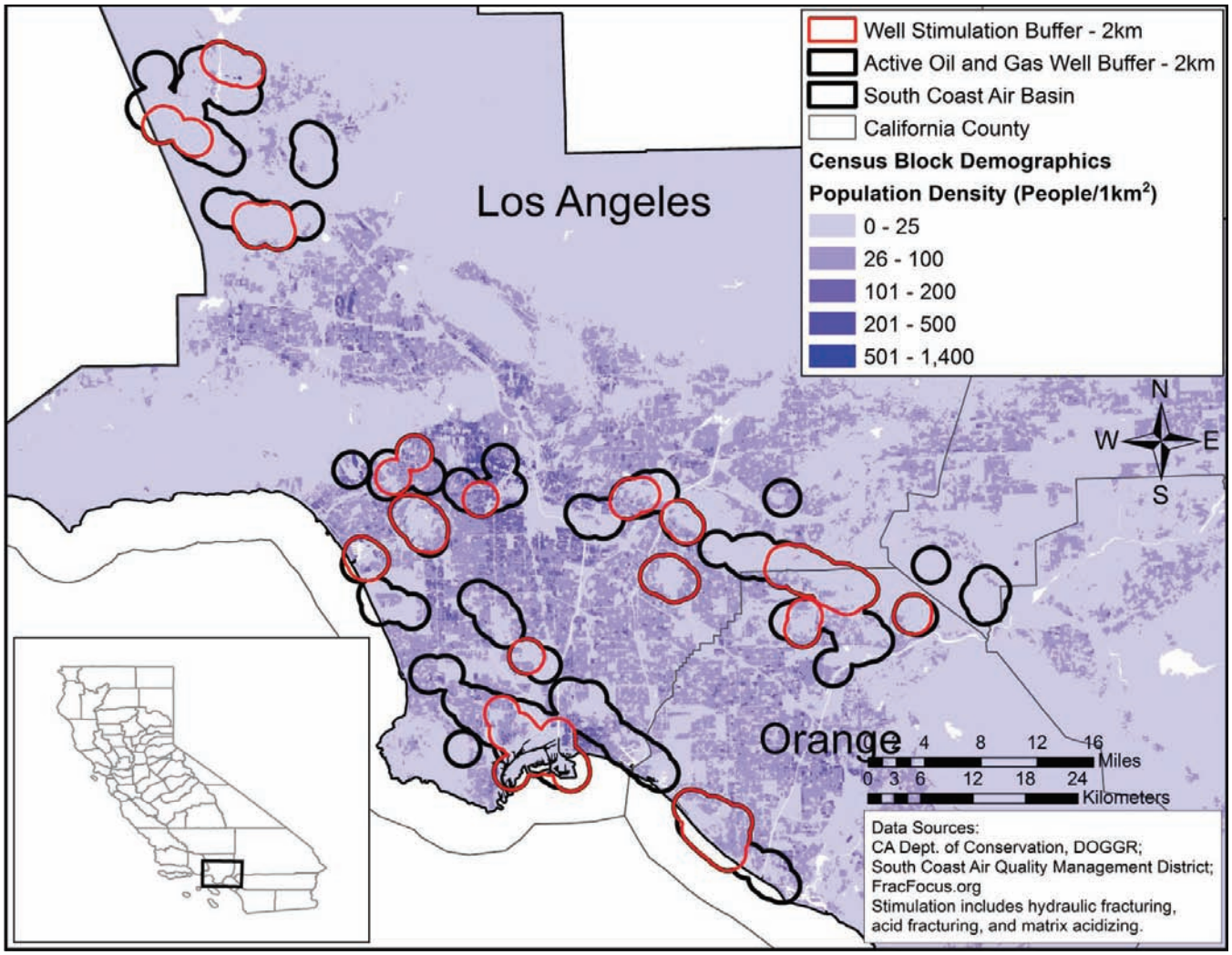


Figure 1.3-12. Population density within 2,000 m (6,562 ft) of currently active oil production wells and currently active wells that have been stimulated (figure from Volume III, Chapter 4 [Los Angeles Basin Case Study]).

Studies from outside of California indicate that, from a public health perspective, the most significant exposures to toxic air contaminants such as benzene, aliphatic hydrocarbons and hydrogen sulfide occur within 800 m (one-half mile) from active oil and gas development. These risks depend on local conditions and the type of petroleum being produced. California impacts may be significantly different, but have not been measured.

Recommendation 6.3. Assess public health near oil and gas production.

Conduct studies in California to assess public health as a function of proximity to all oil and gas development, not just stimulated wells, and develop policies such as science-based surface setbacks, to limit exposures (Volume II, Chapter 6; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Studies]).

Conclusion 6.4. Hydraulic fracturing and acid stimulation operations add some occupational hazards to an already hazardous industry.

Studies done outside of California found workers in hydraulic fracturing operations were exposed to respirable silica and VOCs, especially benzene, above recommended occupational levels. The oil and gas industry commonly uses acid along with other toxic substances for both routine maintenance and well stimulation. Well-established procedures exist for safe handling of dangerous acids.

Occupational hazards for workers who are involved in oil and gas operations include exposure to chemical and physical hazards, some of which are specific to well stimulation activities and many of which are general to the industry. Our review identified studies confirming occupational hazards directly related to well stimulation in states outside of California. The National Institute for Occupational Safety and Health (NIOSH) has conducted two peer-reviewed studies of occupational exposures attributable to hydraulic fracturing across multiple states (not including California) and times of year. One of the studies found that respirable silica (silica sand is used as a proppant to hold open fractures formed in hydraulic fracturing) was in concentrations well in excess of occupational health and safety standards (in this case permissible exposure limits or PELs) by factors of as much as ten. Exposures exceeded PELs even when workers reported use of personal protective equipment. The second study found exposure to VOCs, especially benzene, above recommended occupational levels. The NIOSH studies are relevant for identifying hazards that could be significant for California workers, but no study to date has addressed occupational hazards associated with hydraulic fracturing and other forms of well stimulation in California.

While both hydrochloric acid and hydrofluoric acid are highly corrosive, hydrofluoric acid can be a greater health risk than hydrochloric acid in some exposure pathways because of its higher rate of absorption. State and federal agencies regulate spills of acids and other hazardous chemicals, and existing industry standards dictate safety protocols for handling acids. The Office of Emergency Services (OES) reported nine spills of acid that can be attributed to oil and gas development between January 2009 and December 2014. Reports also indicate that the spills did not involve any injuries or deaths. These acid spill reports represent less than 1% of all reported spills of any kind attributed to the oil and gas development sector in the same period, and suggest that spills of acid associated with oil and gas development are infrequent, and industry protocols for handling acids protect workers.

Employers in the oil and gas industry must comply with existing California occupational safety and health regulations, and follow best practices to reduce and eliminate illness and injury risk to their employees. Employers can and often do implement comprehensive worker protection programs that substantially reduce worker exposure and likelihood of illness and injury. However, the effectiveness of these programs in California has not been evaluated. Engineering controls that reduce emissions could protect workers involved in well stimulation operations from chemical exposures and potentially reduce the likelihood of chemical exposure to the surrounding community.

Recommendation 6.4. Assess occupational health hazards from proppant use and emission of volatile organic compounds.

Conduct California-based studies focused on silica and volatile organic compounds exposures to workers engaged in hydraulic-fracturing-enabled oil and gas development processes based on the NIOSH occupational health findings and protocols.

1.4. References

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Chapter Two

Impacts of Well Stimulation on Water Resources

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2.1. Abstract

We have analyzed the hazards and potential impacts of well stimulation on California's water resources. Our analysis addresses: (1) the characteristics of water use for well stimulation; (2) the volumes, chemical compositions, and potential hazards of stimulation fluids; (3) the characteristics of wastewater production and management; (4) the potential release mechanisms and transport pathways by which well stimulation chemicals enter the water environment; and (5) practices to mitigate or avoid impacts to water.

Available records indicate that well stimulation in California uses an estimated 850,000 to 1.2 million m^3 (690 to 980 acre-feet) of water per year, the majority of which (91%) is freshwater. Hydraulic fracturing has allowed oil and gas production from some new pools where it was not otherwise feasible or economical. We estimate that freshwater use for enhanced oil recovery in fields where production is *enabled* by stimulation was 2 million to 14 million m^3 (1,600 to 13,000 acre-feet) in 2013. (Well stimulation includes hydraulic fracturing, matrix acidizing, and acid fracturing; enhanced oil recovery includes water flooding, steam flooding, and cyclic steaming, described briefly in Section 2.3 below.) Local impacts of water usage appear thus far to be minimal, with well stimulation accounting for less than 0.2% percent of total annual freshwater use within each of the state's Water Resources Planning Areas, which range in size from 830 to 19,400 km^2 (320 to 7,500 mi^2). However, well stimulation is concentrated in water-scarce areas of the state, and an increase in water use or drawdown of local aquifers could cause competition with agricultural, municipal, or domestic water users.

Over 300 unique chemicals were identified as being used in hydraulic fracturing fluids in California. Of the chemicals voluntarily reported as used for hydraulic fracturing in California, over 200 were identified by their unique Chemical Abstracts Service Registry Number (CASRN). Chemical additives reported without a CASRN cannot be fully evaluated for hazard, risk, and environmental impacts due to lack of specific identification. Many of the chemicals reported for use in hydraulic fracturing are also used for other purposes during oil and gas development, including matrix acidizing. In an analysis of acid treatments, including both routine cleaning and matrix acidizing applications, over 70 chemicals were identified as being used in conjunction with acid, of which over 20 were not reported as used in hydraulic fracturing treatments.

Many of the chemicals used in California do not have the basic suite of physical, chemical, and biological analysis required to establish the chemicals' environmental and health profiles. For example, approximately one-half of chemicals used do not have publicly available results from standard aquatic toxicity tests. More than one-half are missing biodegradability, water-octanol partitioning analysis, or other characteristic measurements that are needed for understanding hazards and risks associated with chemicals.

Wastewater generated from stimulated wells in California includes "recovered fluids" (flowback fluids collected into tanks following stimulation, but before the start of production) and "produced water" (water extracted with oil and gas during production). Some information is known about the volumes of recovered fluids and produced water in California. Data from the Division of Oil, Gas, and Geothermal Resources (DOGGR) indicate that there is no substantive difference between the volume of produced water generated from stimulated wells and non-stimulated wells. Recent data submitted to DOGGR by operators show that the volume of recovered fluids collected after stimulation are a small fraction of the injected fluid volumes (<5%) for hydraulic fracturing treatments, but are higher (~50–60%) for matrix acidizing treatments. The data also show that the recovered fluids are a very small fraction of the produced water generated in the first month of operation. These results indicate that some fraction of returning stimulation fluids is present in the produced water from wells that have been hydraulically fractured.

Little is known about the chemical composition of wastewater from stimulated wells and unconventional oil and gas development. Under new regulations, chemical measurements are being made on recovered fluids, and results show that recovered fluids can contain high levels of some contaminants, including total carbohydrates (indicating the presence of guar) and total dissolved solids (TDS). Some data are available on produced water chemistry from conventional wells in California, but there were no data on the composition of produced waters from stimulated wells available during this study. Lack of understanding of the chemistry of produced water from stimulated wells is identified as a significant data gap.

The recovered fluids are typically stored in tanks at the well site prior to injection into Class II disposal wells. In California, produced water is typically managed via pipelines and disposed or reused in a variety of ways. From January 2011 to June 2014, reports

indicate nearly 60% of produced water from stimulated wells was disposed of by infiltration and evaporation using unlined pits. About one-quarter of the produced water from stimulated wells, or about 326,000 m^3 (264 acre-feet), was injected into Class II wells for disposal or enhanced recovery. The disposition method for 17% of the produced water from stimulated wells is either not known or not reported. We note that operators have suggested that the data submitted to DOGGR may not reflect current operating practice due to mistakes in reporting to that agency. Although limited data are available on current treatment and reuse practices in California, it is probable that standard practice for oil-water separation and treatment prior to reuse are unlikely to remove most well stimulation chemicals or their byproducts that may be found in produced water.

Several plausible mechanisms and pathways associated with well stimulation can lead to release of contaminants into surface and groundwater. The release mechanisms of highest priority result from operations that are part of historically accepted practices in the California oil and gas industry, such as disposal of produced water in unlined pits, injection of produced water into potentially protected groundwater, reuse of produced water for irrigation, and disposal of produced water into sewer systems. The concerns related to produced water are relevant to well stimulation because (1) produced water from stimulated wells can contain returned stimulation fluids, and (2) the quality of formation water from stimulated reservoirs could differ from that of conventional reservoirs, and the extent to which they differ is currently unknown. Other concerns of medium priority are accidental releases, some of which need to be better studied. These include the possibility of fractures to serve as leakage pathways (since fracturing depths are much shallower in California than in other parts of the country), leakage through degraded inactive or active wells, and accidents leading to spills or leaks. Finally, there are other releases of low priority, such as operator error and illegal discharges that can be controlled with proper training, oversight, and monitoring.

A few sampling studies have been conducted to assess the impact of hydraulic fracturing on water quality. Only one sampling study has been conducted near a hydraulic fracturing site in California (in Inglewood), but incidents of potential contamination from other regions, such as Pennsylvania (Marcellus formation) and Texas (Barnett, Eagle Ford), can be used to determine potential release mechanisms and hazards, and provide considerations for future monitoring programs in California. While some of the sampling studies indicate that there has been water contamination associated with, and allegedly caused by, well stimulation, other studies did not find detectable impacts due to stimulation. Notably, most groundwater sampling studies do not even measure stimulation chemicals, partly because their full chemical composition and reaction products were unknown prior to this study. In general, groundwater contamination events are more difficult to detect than surface releases, because the effects and release pathways are not visible in the short-term, baseline water quality data are frequently absent, and sufficient monitoring has not been done to confirm the presence or absence of well-stimulation-induced contamination.

2.2. Introduction

Oil and gas development uses water resources and generates wastewater that must be managed by reuse or disposal. There is public concern that well stimulation technologies, especially hydraulic fracturing, may significantly increase water use by the oil and gas industry in California. There is further concern that handling, treatment, or disposal of stimulation fluids may contaminate water resources.

The water cycle of well stimulation consists of five stages (Figure 2.2-1):

1. acquisition of water needed for the stimulation fluids;
2. onsite mixing of chemicals to prepare the stimulation fluids;
3. injection of fluids into a target oil or gas formation during stimulation;
4. recovery of wastewater (flowback and produced water) following stimulation; and
5. treatment and reuse or disposal of wastewaters (after U.S. EPA, 2012a).

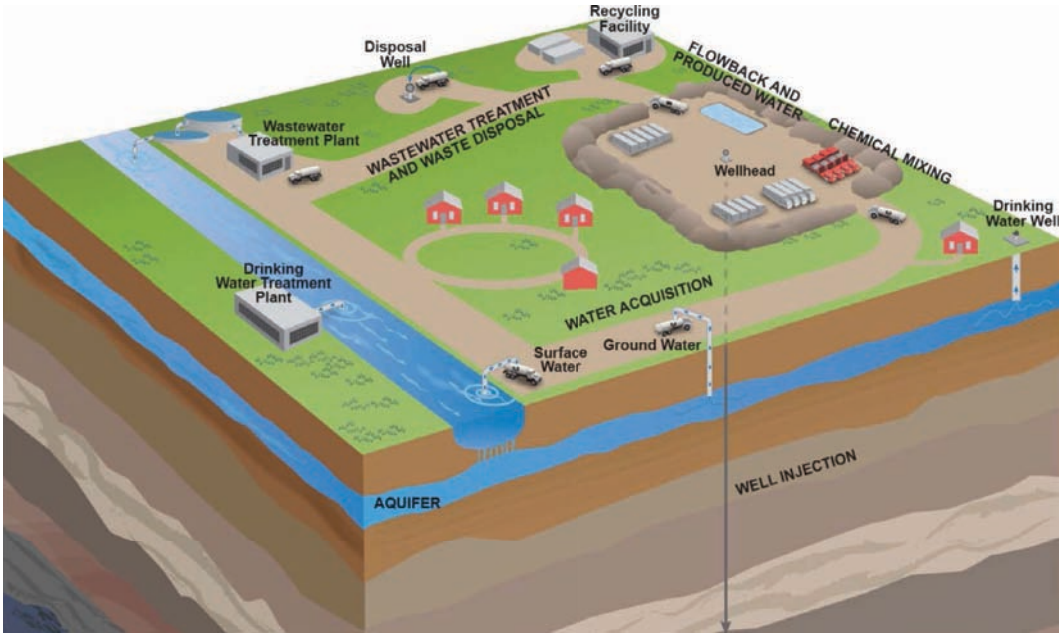


Figure 2.2-1. Five stages of the hydraulic fracturing water cycle (U.S. EPA, 2012a).

In this chapter, we describe and evaluate the hazards posed by well stimulation on California's water resources. Our analysis addresses the following questions:

- What are the volumes of freshwater used for well stimulation in California, and what are the sources of these supplies (e.g., domestic water supplies, private groundwater wells, irrigation sources)? How does water use for well stimulation compare with other uses in California and in the regions where well stimulation is occurring?

- What chemicals are being used for well stimulation in California? How often and in what amounts are these chemicals used? What are the physical, chemical, and toxicological properties of the stimulation chemicals used? To what extent does this chemical use create a hazard for and potential impacts on water resources in California?

- What volumes of recovered fluids and produced water are generated from stimulated wells, and what are the chemical compositions of those waters? Are volumes and chemical compositions of produced water generated from stimulated wells and non-stimulated wells different? How are recovered fluids and produced water managed (e.g., disposal by deep well injection or unlined pits)? Would existing treatment technologies for produced water remove well stimulation chemicals that are being used in California?

- What are the release mechanisms and transport pathways related to well stimulation activities that can potentially contaminate surface and groundwater resources in California? Is there evidence of how these releases can impact both surface and groundwater sources? What is the current state of knowledge about groundwater resources in California, particularly in areas where potential releases can occur?

- What are the best practices and measures that would avoid or mitigate impacts to water?

Our sources of information for addressing these questions consist of publicly accessible data, government reports, industry literature, patents, and peer-reviewed scientific literature. To the extent possible, we use data and information specific to California, which originate from several sources. Data sources for chemical and water use information include the FracFocus Chemical Disclosure Registry (www.FracFocus.org) that was available for early 2011 through mid-year 2014, and documentation required from operators under Senate Bill 4 (SB 4), available as of January 1, 2014, which includes *Well Stimulation Notices* (reporting on planned well stimulation activities) and *Well Stimulation Treatment Disclosure Reports* (reporting after stimulation is complete) (DOGGR, 2014a). We obtained information from the South Coast Air Quality Management District (SCAQMD) on water and chemical use during acid treatments that occurred within their

jurisdiction between June 2013 and June 2014 (SCAQMD 2013; SCAQMD 2014). Data on the location of oil and gas wells in California, both stimulated and non-stimulated, is compiled and distributed by DOGGR as a "shapefile," or geographic data file (DOGGR, 2014b). Additionally, the Central Valley Regional Water Quality Control Board (CVRWQCB) provided data on the disposal practices associated with unconventional oil and gas development (CVRWQCB, 2014; CVRWQCB, 2015). Data on produced water quantity—from both stimulated and non-stimulated wells—were obtained from the Monthly Production and Injection Database maintained by the California Division of Oil, Gas, and Geothermal Resources (DOGGR, 2014c).

In Section 2.3, we summarize the quantities and sources of water currently being used in California for well stimulation. The information on water use data is presented within the context of regional water use and within the context of other oil and gas production activities. Next, in Section 2.4, we describe the type and amount of chemicals being used in stimulation fluids in California. We discuss what is known about hazards associated with well stimulation chemicals, including the physical, chemical, and toxicological properties of the well stimulation chemicals that are used to evaluate risks associated with chemical use. In Section 2.5, we present analyses on the characteristics of wastewater from unconventional oil and gas development in California, including wastewater volumes and composition, as well as their disposal and beneficial reuse practices. In Section 2.6, we describe the release mechanisms and transport pathways relevant to well stimulation activities in California that can potentially lead to contamination of surface and groundwater resources—occurring through spills, surface and subsurface leaks, and current disposal and reuse practices. In Section 2.7, we discuss the potential impacts that the releases can have on surface and groundwater quality by (1) examining incidents (or the lack thereof) of contamination that have been reported in California and other states, and (2) assessing the current state of knowledge about groundwater in California, particularly in areas that may be impacted by well stimulation activities. We then discuss alternative practices that could potentially mitigate hazards induced by well stimulation in Section 2.8. In Section 2.9, we describe several data gaps that were identified through our analyses. We highlight our major findings in Section 2.10 and present conclusions in Section 2.11.

2.3. Water Use for Well Stimulation in California

2.3.1. Current Water Use for Well Stimulation

In this section, we estimate the volume of water currently used for well stimulation in California. Our estimate is based on (1) the average water-use intensity of well stimulation, i.e., the volume of water used per stimulation operation, and (2) the average number of well stimulations occurring in the state each month. We estimated the water-use intensity for each of the three stimulation methods under consideration (hydraulic fracturing, acid fracturing, and matrix acidization) by analyzing records of stimulation fluid volume reported by operators to state regulators and to the website

FracFocus from January 2011 to June 2014.[1] We estimated the number of well stimulation operations occurring each month from a search of oil and gas well records maintained by the California Department of Conservation's Division of Oil, Gas, and Geothermal Resources (DOGGR 2014). In terms of the number of wells that have been hydraulically fractured, we found that over the last decade, operators fractured about 40%–60% of the approximately 300 wells installed per month in California, leading us to estimate that 125 to 175 wells per month are hydraulically fractured in the state. Additional detail on how these quantities were estimated and the associated data sources is provided in Volume I, Chapter 3, *Historical and Current Application of Well Stimulation Technology in California*. Note that limited data were available for certain types of stimulation operations, such as for offshore operations and acid fracturing.

Figure 2.3-1 shows the range of reported water intensity of well stimulation (or the water volume used per stimulation operation) in California by stimulation method and well type. Table 2.3-1 reports our estimated number of well stimulations occurring each month in California and the *average* or *mean* water use intensity of these operations. Based on these data, we estimate that well stimulation in California uses 850,000 to 1,200,000 m^3 (690–980 acre-feet) of water per year. We report a range of estimated water use to represent the uncertainty in the number of operations that are currently taking place. Operators use some water *directly* for well stimulation; chemicals are added to this "base fluid" and injected during stimulation operations. In addition, the availability of hydraulic fracturing has opened up some new areas to oil production, contributing to ongoing water uses for enhanced oil recovery. An analysis of production *enabled* by stimulation is presented below in Section 2.3.3.

1. No single source contained complete information on well stimulations in California prior to 2014, when reporting became mandatory under new regulations required by SB 4. Data sources included the FracFocus website, DOGGR All Wells shapefile, DOGGR Well Stimulation Notices, DOGGR Completion Reports, Central Valley Regional Water Quality Control Board, and the South Coast Air Quality Management District.

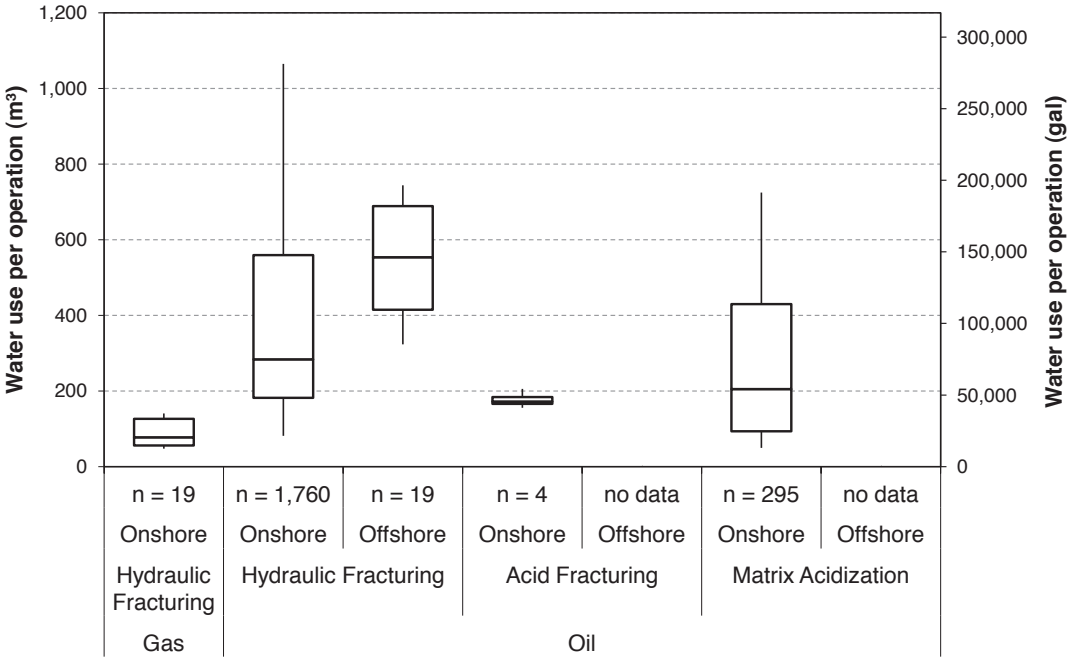


Figure 2.3-1. Boxplots showing range of reported water use per well for well stimulation in California (Jan 2011–Jun 2014) by well type and stimulation type. Box shows the 25th to 75th percentiles of the data. Central line shows the median. Whiskers extend to the 10th and 90th percentiles. Outliers are not shown (Data sources: FracFocus, 2014; DOGGR, 2014a; SCAQMD, 2014; CVRWQCB, 2014).

Table 2.3-1. Estimated volume of water use for oil and gas well stimulation operations in California under current conditions. Number of operations per month estimated for 2004–2014, and average water intensity estimated for Jan 2011 – June 2014.

	Number of operations per month	Average Water Intensity per well (m^3 operation^{-1})	Estimated Annual Water Use (m^3)	Annual Water Use (acre-feet year^{-1})
Hydraulic fracturing	125–175	530	800,000–1,100,000	640–900
Matrix acidizing	15–25	300	54,000–90,000	44–73
Acid fracturing	0–1	170	0–2,000	0–2
Total			**850,000–1,200,000**	**690–980**

Note: We report a range for estimated annual water use to reflect the uncertainty in the number of operations that are currently occurring. As described in Volume I (pages 104-105), we do not know the exact number of stimulation operations that occurred before 2014 because reporting was not mandatory. Our estimate of annual water use was found by multiplying the estimated number of stimulation operations occurring per year in California by the average water-use intensity per operation.

It is worth noting that water use reported to the state by operators for the first 11 months of 2014 (DOGGR, 2014a) was 171,000 m^3 (140 acre-feet), significantly lower than our estimate of the typical annual water use for well stimulation of 850,000 to 1,200,000 m^3 (690 to 980 acre-feet) per year, which was based on data from January 2011 to June 2014 obtained from multiple sources. This discrepancy appears to be due to a slowdown in the number of stimulation operations in 2014 compared to the three previous years. During 2014, there was an average of 44 stimulation operations each month, down from an estimated 140 to 200 operations per month during the years from 2011 through 2013. There could be several causes for this slowdown, including uncertainty among operators related to new regulations, public pressure, or dropping oil prices in the second half of 2014. The average water use per stimulation operation reported by operators in 2014 also appears to be somewhat lower than the historical rates of water use. Operators used an average of 390 m^3 (0.32 acre-feet) for hydraulic fracturing operations in 2014, lower than the average water use of 530 m^3 (0.43 acre-feet) during the previous three years.

2.3.2. Water Sources

We investigated where operators are acquiring water for well stimulation by analyzing data from well stimulation completion reports. Under new SB 4 regulations effective January 1, 2014, operators are required to send DOGGR a *Well Stimulation Treatment Disclosure Report*, referred to here as a "completion report," within 60 days after completing stimulation. On this form, operators identify the source of the water they used as a base fluid for stimulation. They also identify the *type* of water that makes up the base fluid, i.e., "water suitable for irrigation or domestic purposes," "water **not** suitable for irrigation or domestic purposes," or "fluid other than water."

There were 495 completion reports filed by operators and published by DOGGR between January 1 and December 10, 2014 (DOGGR, 2014a). Among these reports, there were 15 where the operator reported the volume of water use as zero, which we believe to be an error. We removed these records, and analyzed the remaining 480 reported stimulations. A summary of reported water use by source is shown in Table 2.3-2.

Operators obtained the water needed for well stimulation from nearby irrigation districts (68%), produced water (13%), operators' own wells (13%), a nearby municipal water supplier (4%), or a private landowner (1%). About a tenth of the total water volume was identified as water **not** suitable for irrigation or domestic use. Why the water was deemed unsuitable was not specified, but it is presumed that the water had high salt content. In California, freshwater is defined as having a TDS content less than 3,000 mg L^{-1} (see Section 2.7).

Table 2.3-2. Water sources for well stimulation according to 480 well stimulation completion reports filed from January 1, 2014 to December 10, 2014.

Water Source	Number of Operations	Total Water Volume		Percent of Total Water Volume
		m^3	acre-feet	
Irrigation district	399	117,000	95	68%
Produced water	43	23,000	18	13%
Own well	28	22,000	18	13%
Municipal water supplier	9	7,000	6	4%
Private landowner	1	2,000	2	1%
Total	**480**	**171,000**	**140**	**100%**

Of the 495 completion reports filed, all but two were for operations in Kern County. Many of the Kern County operations (397, or 83%) used water from the Belridge Water Storage District, which was formed to serve farmers in central Kern County with water provided by the State Water Project. The two submitted completion reports from outside of Kern County were in Ventura County and conducted by Aera Energy. These operations both used water from the Casitas Municipal Water Supply District, which provides water to about 70,000 people and several hundred farms in western Ventura County.

2.3.3. Water Use for Enhanced Oil Recovery

In this section, we analyze water use related to enhanced oil recovery. This analysis serves two purposes: first, to understand how the freshwater demand for well stimulation compares to freshwater demand for enhanced oil recovery; and second, to estimate the additional freshwater demand that occurs when stimulation technology allows production from new zones to be developed. The application of well stimulation technology has enabled production in some new pools where it would not have been likely to occur otherwise. The development of these pools creates additional demands for water, particularly for enhanced oil recovery. This water demand can be considered additional to the water that is used directly as the base fluid for well stimulation operations such as hydraulic fracturing. Below, we examine the water use for what we refer to as production *enabled* by well stimulation.

Water is used for a number of different purposes throughout the oil and gas production process, including drilling, well completion (during which well stimulation occurs), well cleanout, and for some types of enhanced oil recovery (EOR). Initially, oil production consists of simply producing oil and gas from the reservoir (primary production). In California, production in most reservoirs has been occurring for a span of time ranging from several decades to more than a century, so primary production has ended. Continued production requires additional processes including water flooding (secondary recovery) or, in California, steam flooding or cyclic steaming (two of many types of tertiary recovery). Water flooding and steam flooding involve continuous injection to push oil

toward production wells, and, in the case of steam, to also reduce the oil's viscosity along with other effects. Cyclic steam injection involves periodic injection of steam followed by a well shut-in period to allow the heat to reduce the oil viscosity, followed by a period of production, after which the cycle repeats.

We obtained information about the location and volume of water used for enhanced oil recovery from DOGGR's Production/Injection Database (DOGGR, 2014c). According to this data, there were 29,061 wells that injected water or steam into oil and gas reservoirs in 2013. DOGGR's database also contained information on the *type* and *source* of water injected.

We performed a series of analysis to determine the volume, type, and source of water used for EOR in California. These results are reported in Table 2.3-3. We found that in 2013, the total volume of water (or water converted to steam) injected by operators totaled 443 million m^3 (360,000 acre-feet).

In terms of water *source*, operators reported that two-thirds of the water injected (288 million m^3 or 233,000 acre-feet) was produced water, or water that is pumped to the surface along with oil and gas, and subsequently re-injected back into the formation, largely forming a closed loop system. Operators using solely produced water for injection are not generally competing with other water users. Approximately one-third of injected water was not produced water, which means operators obtained this water from another source. We refer to this water here as *externally sourced* water. Another 23% of injected water was externally sourced salt water; this includes saline groundwater (94 million m^3, or 76,000 acre-feet) and ocean water (7 million m^3, or 5,000 acre-feet).

In addition to produced water, however, operators are also injecting externally sourced freshwater for enhanced oil recovery. In 2013, operators reported 3% of injected water as "freshwater" (15 million m^3 or 12,000 acre-feet). However, we estimated freshwater use may be as high as 14%, based on ambiguity in the reporting categories in DOGGR's database. DOGGR's database allows operators to report water type in one of five categories; one of these is labeled "freshwater," but some of the other categories may be composed partly or entirely of freshwater. These ambiguous categories include "water combined with chemicals such as polymers," "another kind of water," and "not reported." By combining these categories with the freshwater category, we estimate injected freshwater in 2013 may have been as high as 60 million m^3 (49,000 acre-feet).

In order to understand *where* operators are obtaining freshwater for EOR, we performed another set of queries and analyses using DOGGR's Production/Injection database. In 2013, operators reported that they obtained freshwater for injection from several sources: domestic water systems (72%), water source wells (25%), wastewater from an industrial facility (1.6%), and not reported (1.4%) or reported as "another source or combination of the above sources" (0.1%).

Table 2.3-3. Breakdown of injected water for enhanced oil recovery by source and type of water, in million m^3 per year, in 2013. This does not include water for well stimulation.

All sources:	million m^3			
Produced from an oil or gas well	288	65%		
Ocean	<0.001	<0.1%		
Other Sources	155	35%		
Total	**443**			

Breakdown of water type in "Other sources" above:		million m^3		
Salt water	94	61%		
Water combined with chemicals such as polymers	22	14%		
Not Reported	17	11%		
Another kind of water	6	3.9%		
Freshwater		15	9.8%	
Total other sources		**155**		

Source of freshwater listed above:	million m^3	
Domestic water systems	11	72%
Produced from a water source well	4	25%
Wastewater from an industrial facility	0.2	1.6%
Not reported	0.2	1.4%
Another source or combination of the above sources	0.015	0.1%
Total all externally sourced freshwater	**15**	

Note: Table figures may not add due to rounding.

We analyzed how much freshwater is used for EOR in fields where production is *enabled* by well stimulation technology. To do this, we summarized freshwater use for EOR in pools that we had previously categorized as having production enabled by well stimulation. These are typically formations with low transmissivity where oil or gas production is not economically feasible without fracturing. We identified these pools by analyzing well records maintained by DOGGR, and identified 68 pools where the majority of new production wells from 2002 to 2013 were hydraulically fractured (see Volume I for detailed analysis. We estimate that water use for EOR in these pools ranged from 2 million to 14 million m^3 (1,600 to 13,000 acre-feet) in 2013, while freshwater use for EOR in all other oil and gas fields was 13 million to 44 million m^3 (11,000 to 36,000 acre-feet) in 2013, as shown in Figure 2.3-2. Thus, we may conclude that between 15% and 30% of freshwater use for EOR in California in 2013 can be attributed indirectly to the application of well stimulation.

We also compared the total volume of freshwater that oil and gas operators use for well stimulation to the volume used for enhanced oil recovery. Based on our estimates above, operators used from 2 to 15 times more freshwater for EOR than they used for well stimulation in 2013. Figure 2.3-2 compares the estimated volume of water used for well stimulation with the volume of water injected for EOR in 2013.

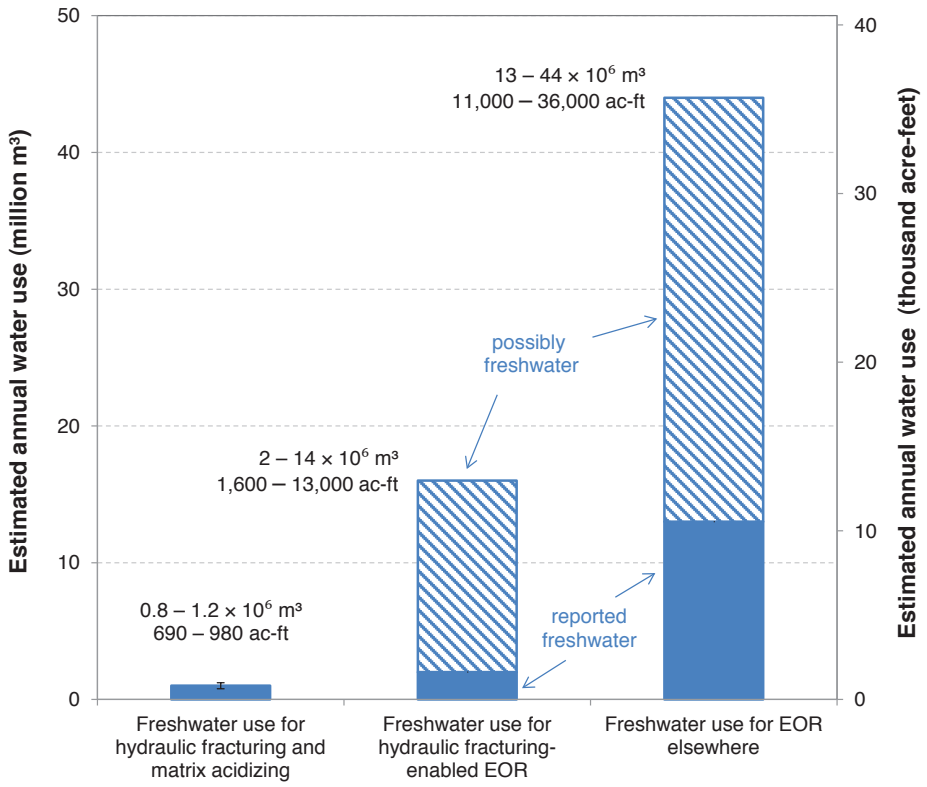


Figure 2.3-2. Estimated annual freshwater use for well stimulation (left), enhanced oil recovery (EOR) in 2013 in reservoir where most wells are hydraulically fractured (middle), and EOR in 2013 in other reservoirs (right). Well stimulation including hydraulic fracturing occurs before the well goes into production. EOR occurs throughout production.

Note: The solid bar in this figure represents water volume explicitly classified as freshwater in the DOGGR Production Database. The hatched area represents water used for EOR that is reported as a type that may be all or part freshwater. When we include "water combined with chemicals such as polymers," "another kind of water," and blank records (unknown water type), freshwater use for enhanced oil recovery may be as high as 60 million m³ (49,000 acre-feet).

2.3.4. Water Use for Well Stimulation in a Local Context

Water use for well stimulation and stimulation-enabled EOR in California is small in the context of the state's total water use; our estimate of this water use for well stimulation is less than 2 million m^3 (<2,000 acre-feet) per year (Table 2.3-1 and Figure 2.3-2), while human water use statewide averages about 56 billion m^3 (45 million acre-feet) per year (DWR, 2014a). Water concerns, however, are local, and the impacts of that water use should be evaluated within a local context. Where oil and gas extraction occurs alongside other uses, it can mean competition over a limited resource, especially where the oil and gas industry is usually willing and able to pay more for water than irrigators or other water users (Freyman, 2014; Healy, 2012).

To get a better sense of water use in regions where well stimulation has been reported, we examined water use within Planning Areas, also referred to as "PAs". PAs are geographic units created by the California Department of Water Resources (DWR) for the planning and management of the state's water resources. DWR divides the state into 56 PAs, ranging in size from 830 to 19,400 km^2 (320 to 7,500 mi^2), with an average size of 6,700 km^2 (2,600 mi^2). PA boundaries typically follow watershed boundaries, but are sometimes coincident with county boundaries or hydrologic features, such as rivers and streams.

From January 2011 to the end of May 2014, well stimulation was documented in 19 of the state's 56 PAs (Table 2.3-4). We estimated the amount of water used for well stimulation and hydraulic-fracturing-enabled EOR by PA and compared that water use to total water use for the area (Table 2.3-4).

Table 2.3-4. Estimated annual water use for well stimulation and hydraulic fracturing-enabled EOR by water resources Planning Area.

Planning Area	For well stimulation operations (m^3)	For enabled EOR (m^3)	Total water use (stimulation + EOR, m^3)	% of water use in Planning Area
Santa Ana	1,300		1,300	0.000082%
Metro Los Angeles	25,000		25,000	0.0013%
Santa Clara	11,000		11,000	0.0018%
Central Coast Southern	270		270	0.000043%
Semitropic	930,000	2,000,000*	2,900,000	0.19%
Kern Delta	2,100		2,100	0.00011%
Kern Valley Floor	18,000		18,000	0.0016%
Uplands	9,300		9300	0.015%
Central Coast Northern	900		900	0.00011%
Western Uplands	2,900		2,900	0.10%
San Luis West Side	260		260	0.000017%
Lower Kings-Tulare	750		750	0.000031%
North Bay	930		930	0.00035%
San Joaquin Delta	440		440	0.000038%
Sacramento River Delta	1,300		1,300	0.00018%
Central Basin, West	480		480	0.000044%
Colusa Basin	2,900		2,900	0.00011%
Butte-Sutter-Yuba	3,100		3,100	0.000098%
Offshore	6,600		6,600	n/a
Total	**1,000,000**	**2,000,000**	**3,000,000**	**0.0057%**

**In this table, we report the low estimate for water use for EOR in fields where production is enabled by well stimulation. In Section 2.3.3, we found that this water use may range from 2 million to 14 million m^3 (1,600 to 13,000 acre-feet).*

Note: Water use estimates for Planning Areas are for the year 2010 (from DWR, 2014b). Numbers may not sum to the total values due to rounding.

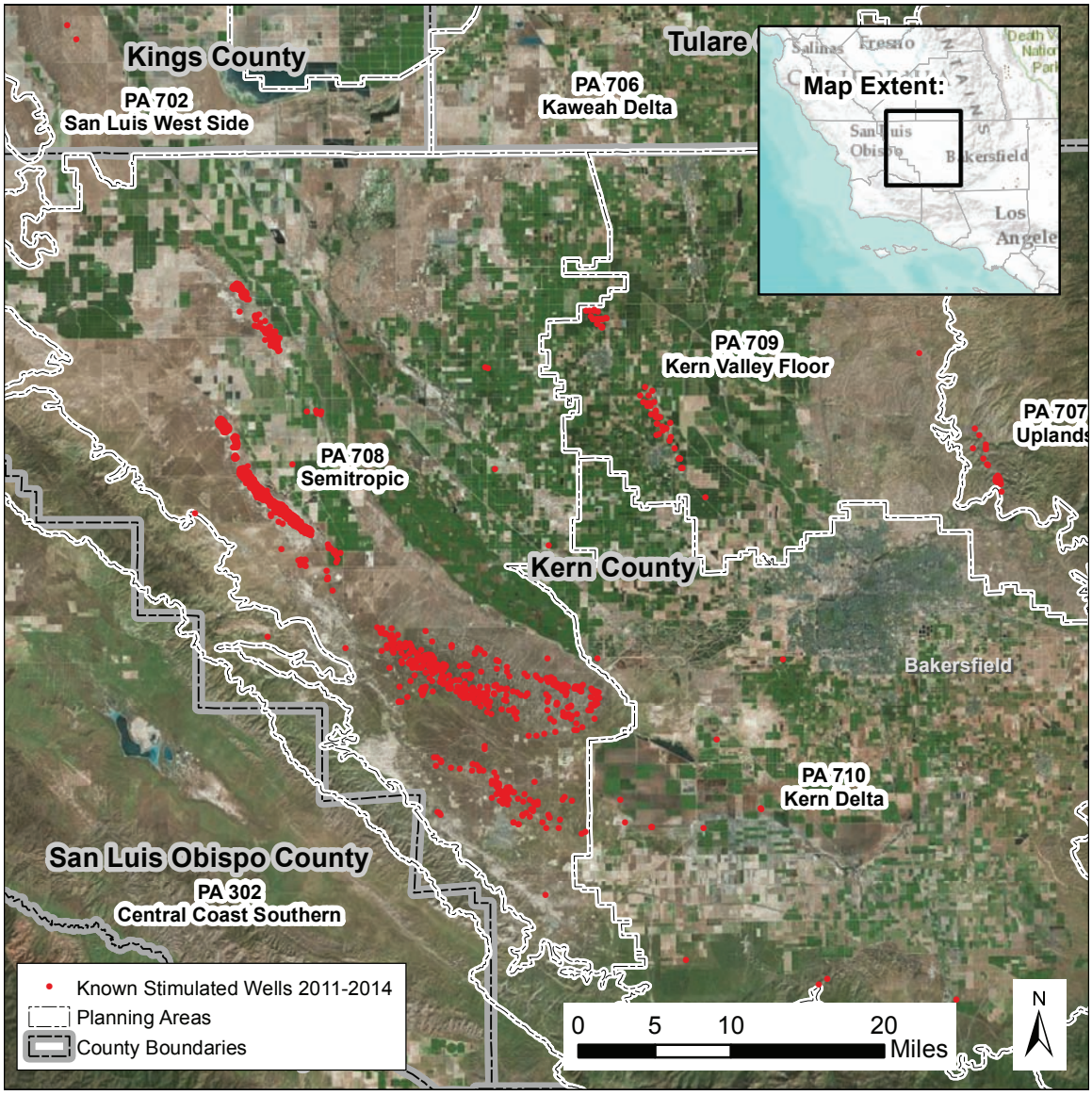


Figure 2.3-3. Map showing oil and gas wells stimulated from January 2011 through June 2014 and Water Resources Planning Areas in the Tulare Lake basin.

The majority of well stimulation operations occurred in western Kern County in the Semitropic PA (Figure 2.3-3). All of the reported matrix-acidizing operations are in this PA as well, as is all the freshwater use for EOR enabled by hydraulic fracturing. Water use for well stimulation and hydraulic-fracturing-enabled EOR comprises less than 0.1% of human water use in almost all PAs where stimulation occurs. Water use by PA attributable to well stimulation ranged from a low of 270 m^3 (0.22 acre-feet) in the Central Coast Southern and San Luis West Side PA, to a high of 2,900,000 m^3 (2,400 acre-feet) in the Semitropic PA (Table 2.3-4). Even within the Semitropic PA, where the vast majority of well-stimulation-related freshwater use occurs, water use for well stimulation accounts

for only 0.19% of water use (Table 2.3-5). Within this PA, the largest water use is for irrigated agriculture, which used 1,500 million m^3 (1.2 million acre-feet) in 2010. This is followed by energy production and urban use.

Table 2.3-5. Estimated annual water use for well stimulation and hydraulic fracturing-enabled EOR in the Semitropic Planning Area compared to applied water volumes estimated by DWR for 2010. Note water use for hydraulic fracturing-enabled EOR was subtracted from energy production water volume estimated by the DWR.

	million m^3 $year^{-1}$	acre-feet $year^{-1}$
Well stimulation and hydraulic fracturing-enabled EOR	2.9	2,400
Estimated Applied Water in 2010*		
Energy Production	19	15,000
Urban (commercial, industrial, residential)	10	8,000
Agricultural	1,500	1,200,000
Total	**1,530**	**1,220,000**

**Numbers may not sum to total due to rounding*

Despite its relatively low freshwater use, concerns have been raised by some water analysts and environmental organizations that freshwater use for hydraulic fracturing could have a negative impact because it is concentrated in relatively water-scarce regions, and the additional demand could strain available supplies (e.g., Summer, 2014; Center for Biological Diversity, 2015). Competition for water could become more critical in the face of extended drought.

Most of the hydraulic fracturing in California takes place in the San Joaquin Valley, where groundwater has been over-drafted by agriculture for over 80 years, causing a host of problems, including subsidence of the land surface. The 8-meter drop in the land surface near Mendota, California, is among the largest ever that has been attributed to groundwater pumping (Galloway et al., 1999). New water demands on top of already high competition for water could further deplete the region's aquifers, as has been observed in other water-scarce regions of the U.S. where hydraulic fracturing is occurring (Reig et al., 2014). This could cause concern for smaller communities and domestic users that rely on local groundwater. In the San Joaquin Valley, farmers and communities also depend on imported water delivered by canals, deliveries of which have become increasingly unreliable in recent years (DWR, 2014a). On the other hand, in some areas, produced water from oil fields that have low salt concentrations can be a source of water, and is being reused for a variety of beneficial purposes, including for irrigation and groundwater recharge, as discussed in Section 2.6.

2.4. Characterization of Well Stimulation Fluids

2.4.1. Understanding Well Stimulation Fluids

Understanding the composition, or formulations, of well stimulation fluids is an important step in defining the upper limits of potential direct environmental impacts from hydraulic fracturing and other well stimulation technologies. The amounts of chemicals added to well stimulation fluid define the maximum possible mass and concentrations of chemical additives that can be released into the environment. The chemicals added to well stimulation fluid might also influence the release of metals, salts and other materials found naturally in oil and gas bearing geological formations. Due to the economic value of individual well-stimulation-fluid formulations and competition between oil field service companies, operators and service companies have been generally reticent about releasing detailed information concerning the types and amounts of chemicals used in specific formulations. Often when information is released, the information may be incomplete (e.g., Konschnik et al., 2013). This lack of transparency has heightened uncertainty and concerns about the chemicals used in well stimulation fluid.

We investigated the composition of well stimulation fluids that are used in California with the objectives of (1) developing an authoritative list of chemicals used for well stimulation in California, (2) determining the concentrations at which the chemicals are used, and (3) estimating the amount (mass) of each chemical that is used per well stimulation. Characteristics of stimulation chemicals, including aquatic and mammalian toxicity were also evaluated (see below and Chapter 6). Chemical disclosures include information on the volume of water used as a "base fluid" and the concentrations of chemicals present in individual well-stimulation-fluid formulations, from which the mass of chemicals used per stimulation can be estimated.

We compiled the reported uses of chemical additives in hydraulic fracturing and acid treatments, and evaluated the information using numerous approaches. A list containing hundreds of chemicals can be initially bewildering, even to experts, and it is helpful to understand the significance of individual chemicals or chemicals in mixtures in the context of their frequency of use, the amounts used, and their hazardous properties, such as toxicity. Other information to help understand and evaluate chemicals includes the purpose of their use, the class of chemical to which they belong, and other distinguishing characteristics, such as vapor pressure and water solubility. Previous studies have evaluated and characterized chemical additives to well stimulation fluids that are in common use nationally (Stringfellow et al., 2014; U.S. House of Representatives Committee on Energy and Commerce, 2011; U.S. EPA, 2012a). In this study, we examine chemicals specifically used in California and develop a comprehensive list of well-stimulation-fluid additives for California.

In this section, chemicals known to have been constituents of well stimulation fluids in California are ranked and characterized for their hazardous properties in relation to aquatic environments. Chapter 6 addresses hazards in the context of human health.

Understanding hazard is important; however, the risk associated with any individual chemical is a function of the release of the material to the environment, how much material is released, the persistence of the compound in the environment, and many other properties and variables that allow a pathway to human or environmental receptors. A full risk assessment is beyond the scope of this study. However, information on hazard, toxicology, and other physical, chemical, and biological properties developed in this section are fundamental to the understanding of environmental and health risk associated with well stimulation treatments in general, and well stimulation fluid specifically.

2.4.2. Methods and Sources of Information

Prior to the enactment of SB 4 authorized regulation in California in January 2014, all information from industry on the composition of well stimulation fluid was released on a voluntary basis. A primary source of data for the analysis in this section was voluntary disclosures reported to the FracFocus Chemical Disclosure Registry (http://fracfocus.org/). The data used in this analysis include disclosures entered into the Chemical Disclosure Registry for hydraulic fracturing in California prior to June 12, 2014. This analysis includes listing all the chemicals used in 1,623 hydraulic fracturing treatments conducted in California between January 30, 2011 and May 19, 2014 (Appendix A, Table 2.A-1). The mass used per treatment and the frequency of use were only calculated using well stimulation treatments that had complete records (Appendix A, Table 2.A-1). A complete treatment record was a record that included the volume of base fluid used, the concentration of the base fluid and the concentration of each chemical used as percent of total treatment fluid mass, and where the sum of the reported masses was between 95% and 105%. Of the 1,623 reported applications, 1,406 (87%) met the criteria for complete records.

The Chemical Disclosure Registry only includes disclosures for hydraulic fracturing treatments and does not include other well stimulation treatments, such as matrix acidizing treatments. Sources of information for acid treatments include Notices of Intent and Completion Reports submitted to DOGGR since December 2013 under new SB 4 regulations and chemical use reported to SCAQMD under reporting regulations in effect since 2013 (SCAQMD, 2013).

There were an estimated 5,000 to 7,000 hydraulic fracturing treatments in California between 2011 and 2014, suggesting that the voluntary disclosure record represents only one-third to one-fifth of the estimated total hydraulic fracturing treatments. However, the disclosures include the major producers and service companies operating in California, including Baker Hughes, Schlumberger, and Halliburton. The chemical additives listed in the voluntary disclosures were consistent with additives described in information available from industry literature, patents, scientific publications, and other sources, such as government reports (e.g., Gadberry et al., 1999; U.S. EPA, 2004; Baker Hughes Inc., 2011; 2013; Stringfellow et al., 2014). Therefore, it is concluded that this list is representative of chemical use for well stimulation in California.

The hazard that a material may present if released to the environment is assessed using a number of criteria, including the toxicity of the chemical to aquatic species selected to represent major trophic levels of aquatic ecosystems. Common standard test species include the fathead minnow (*Pimephales promelas*); various species of trout; daphnia, such as *Daphnia magna*; and various species of green algae (U.S. EPA, 1994; OECD, 2013). The test species represent a basic aquatic food chain of primary producers (algae), grazers (daphnia), and predators (minnows). The species tested are typically selected on the basis of availability, regulatory requirements, and past successful use. Other test species (e.g., trout) may be selected for testing based on commercial, recreational, and ecological importance. Standardized test data for lethality are typically reported as median lethal dose (LD_{50}) for mammals and median lethal concentration (LC_{50}) for fish. In the case of aquatic crustaceans and algae, the effective concentration at which 50% of the test population is adversely affected is determined and reported as the median effective concentration (EC_{50}). Since aquatic toxicity tests are highly standardized, the results can be used to compare and contrast industrial chemicals (Stringfellow et al., 2014). Experimental tests against aquatic species are an important component of an ecotoxicological assessment.

For this study, we examine the acute toxicity of individual chemicals to fathead minnows, daphnia, and algae. Acute toxicity data were collected only for the chemicals used in well stimulation in California that were identified by CASRN. Toxicity data were gathered from publicly available sources as shown in Table 2.4-1. Computational methods (EPI Suite) were applied in an attempt to fill data gaps when chemicals have not been thoroughly tested using experimental methods (Mayo-Bean et al., 2012; U.S. EPA, 2013c). The U.S. EPA cautions that EPI Suite is a screening-level tool and should not be used if acceptable measured values are available (U.S. EPA, 2013c). In this study, we only included EPI Suite results if experimental results were not available. In the case of green algae, insufficient experimental results were found, and only EPI Suite results were used in the analysis. The EPI Suite values for freshwater fish were also used to fill data gaps for both fathead minnow and trout toxicity (Appendix B, Figure 2.B-1).

Ecotoxicity results were interpreted in the context of the Globally Harmonized System (GHS) criteria for the ranking and classification of the acute ecotoxicity data. A similar approach was taken to evaluate mammalian toxicity and is described in Chapter 6. The United Nations Globally Harmonized System (GHS) of Classification and Labeling of Chemicals was used to categorize chemicals based upon their LD_{50}, LC_{50}, or EC_{50} values (Appendix A, Tables 2.A-2 and 2.A-3) (United Nations, 2013). In the GHS system, lower numbers indicate greater toxicity, with a designation of "1" indicating the most toxic compounds (Appendix A, Tables 2.A-2 and 2.A-3). Chemicals for which the LD_{50}, LC_{50}, or EC_{50} exceeded the highest GHS category were classified as non-toxic.

Physical and chemical data for fracturing fluid additives was obtained from online chemical information databases, government reports, chemical reference books, materials safety data sheets, and other sources as previously described (Stringfellow et al., 2014).

Physical and chemical data are mostly based on laboratory tests using pure compounds. Physical, chemical, and toxicological properties were selected for inclusion in this study based on their use in environmental fate and transport studies, treatability evaluations, remediation efforts, and risk assessments (Stringfellow et al., 2014). Chemicals used in well stimulation were categorized as *non-biodegradable* or *biodegradable* using OECD guidelines (OECD, 2013). Biodegradability is useful for determining the effectiveness of biological treatment for wastewaters and the fate of chemicals released into the environment. In the absence of measured biodegradation data, computational methods developed for the U.S. EPA (e.g., BIOWIN) were used to estimate biodegradability (U.S. EPA, 2012b).

Table 2.4-1. Sources for physical, chemical, and toxicological information for chemicals used in well stimulation treatments in California.

U.S. EPA (Environmental Protection Agency), ACToR (Aggregated Computational Toxicology Resource) Database, 2013, http://actor.epa.gov/actor/faces/ACToRHome.jsp
National Library of Medicine, ChemIDplus Advanced. http://chem.sis.nlm.nih.gov/chemidplus/
U.S. EPA (Environmental Protection Agency) and Office of Pesticide Programs, ECOTOX Database Version 4.0, 2013, http://cfpub.epa.gov/ecotox/
European Chemicals Agency (ECHA), International Uniform Chemical Information Database (IUCLID), CD-ROM Year 2000 Edition, 2000.
National Institute of Technology and Evaluation, Chemical Risk Information Platform (CHRIP). http://www.safe.nite.go.jp/english/db.html
R.J. Lewis, N.I. Sax, Sax's dangerous properties of industrial materials, 9th ed., Van Nostrand Reinhold, New York, NY, 1996
Syracuse Research Corporation PhysProp Database
National Library of Medicine, Toxicology Data Network (TOXNET) Hazardous Substance Data Bank (HSDB), 2013, http://toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB
SciFinder, Chemical Abstract Service, Colombus, OH, https://scifinder.cas.org
Materials Safety Data Sheets from Sigma-Aldrich, BASF, Spectrum, ExxonMobil, Alfa Aesar, Clariant, and other chemical suppliers
Organization for Economic Cooperation and Development (OECD) - Screening Information Data Set
California Prop 65, Chemicals Known to the State to Cause Cancer or Reproductive Toxicity. http://www.oehha.ca.gov/prop65/prop65_list/files/P65single050214.pdf
International Agency for Research on Cancer (IARC), IARC Monographs on the Evaluation of Carcinogenic Risks to Humans, World Health Organization. http://monographs.iarc.fr/ENG/Classification/ClassificationsCASOrder.pdf
U.S. EPA (Environmental Protection Agency), EPI Suite, Experimental Values
Toxic Substance Control Act Test Submissions 2.0, 2014, http://yosemite.epa.gov/oppts/epatscat8.nsf/ReportSearch?OpenForm

2.4.3. Composition of Well Stimulation Fluids

2.4.3.1. Chemicals Found in Hydraulic Fracturing Fluids

A list of chemical additives reported to have been used in California for hydraulic fracturing treatments is shown in Appendix A, Table 2.A-1. The list includes frequency of use, concentration, and mass of chemicals used for hydraulic fracturing in California, as reported to the FracFocus Chemical Disclosure Registry prior to June 12, 2014. The list contained in Table 2.A-1 includes only the subset of hydraulic fracturing treatment data for which the sum of the reported additives was 100% ± 5%.

As can be seen in Table 2.A-1, not all additives were identified by CASRN, which is a standardized system for the clear and singular identification of chemicals, otherwise known by various common names, trade names, or product names, which may or may not be specific. Of the disclosed chemical additives, there were approximately 230 chemicals or chemical mixtures identified by CASRN; others were identified by name only. Over 100 chemicals could not be positively identified because a CASRN was not provided. After analysis and standardization of chemical names, over 300 chemicals or chemicals mixtures were identified by unique name or CASRN. Since in many cases generic names were used for chemical additives on the disclosures (e.g., surfactant mixture, salt, etc.), any enumeration of the number of chemicals used in hydraulic fracturing should be considered approximate (Table 2.A-1). Many of the additives used in hydraulic fracturing are also used in other routine oil and gas operations, such as well drilling. Other chemicals are specific to well stimulation, such as guar and borate cross linkers.

Disclosures that do not provide CASRN for each entry do not allow definitive identification of the well-stimulation-fluid additive. However, chemical names are generally informative, and each identified substance was investigated and, where possible, referenced to specific products sold by the major suppliers of well stimulation services and chemicals in California. There was a median of 23 individual components—including base fluids, proppants, and chemical additives—used per treatment (Figure 2.4-1). The number of unique components used as reported here differs from a recent study by the U.S. EPA, which reported a median of 19 chemical additives used per treatment in an analysis of 585 disclosures (U.S. EPA, 2015a). The difference between these two studies results in part because of differences in the number of disclosures examined (585 vs. 1,406 for this study), but also because the number here includes base fluids and proppants, while the U.S. EPA study did not include these in developing the median value of 19 (U.S. EPA, 2015a). The disclosures include descriptions for chemicals added for the purpose of stimulation (e.g., water, gelling agents, biocides, etc.) and entries for so-called impurities found in the chemicals used for formulating well-stimulation fluid. In many cases, impurities are reported without concentration data or mass concentrations of <0.001% of the mass of the injected fluid.

Impurities are common in industrial-grade chemicals, which are rarely 100% pure. Impurities are frequently residual feedstock materials from the manufacturing process or solvents and other materials added to control product consistency or handling properties. Table 2.A-1 gives the reported median chemical concentration in well stimulation fluid. Chemicals can be added at hundreds and sometimes thousands of mg kg^{-1} of fluid. Even the impurities, which are not specifically added for a purpose directly related to well stimulation, can occur at high concentrations in well stimulation fluid. For example, magnesium chloride and magnesium nitrate are inactive ingredients (e.g., impurities) found in biocides containing 2-methyl-3(2H)-isothiazolone and 5-chloro-2-methyl-3(2H)-isothiazolone (Miller and Weiler, 1978). Even though impurities are not added specifically for well stimulation, they must be considered during an evaluation of the hazards associated with hydraulic fracturing.

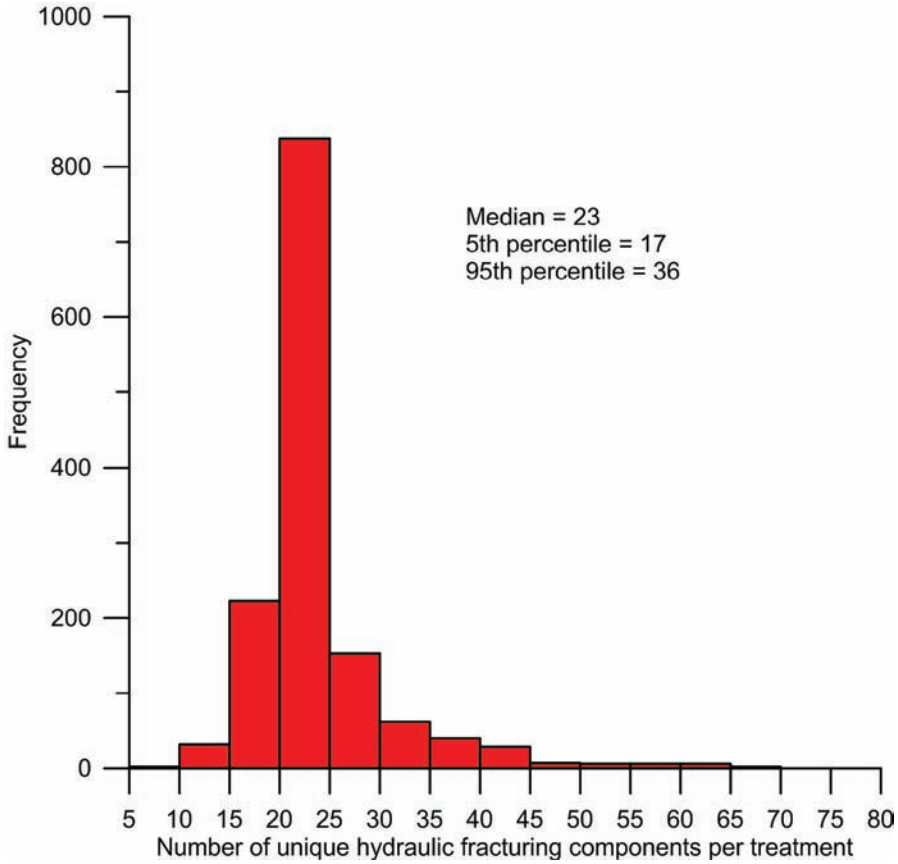


Figure 2.4-1. Frequency distribution of the number of components used per hydraulic fracturing operation in California. Only complete records were included in the analysis where the sum of the treatment components was 100 ± 5% (N=1,406).

2.4.3.2. Chemicals Found in Matrix Acidizing Fluids

There are well stimulation treatments used in California that involve the use of strong acids, including hydrochloric and hydrofluoric acid (see Volume I, Chapter 2 and 3 and California Council on Science and Technology (CCST) et al., 2014). Due to the absence of state-wide mandatory reporting on chemical use in the oil and gas industry, it is not known how much acid is used for oil and gas development throughout California. However, available information suggests that there are approximately twenty matrix acidizing treatments in California per month, but detailed chemical information on specific treatments are not available. Parts of southern California have mandatory reporting on the use of all chemicals used for well drilling, reworks, and well completion activities (http://www.aqmd.gov/). Analysis of these data suggests acid use is widespread and common for many applications in the industry.

As of December 2013, under interim regulations, DOGGR has required operators to submit a "Notice of Intent" for well stimulation treatments, including matrix acidizing. These notices include a list of chemicals that may be used in a planned well stimulation treatment. Analysis of these mandatory Notices of Intent that were publicly available between December 2013 and June 2014 found 70 chemicals identified by CASRN. Seven compounds reported in Notice of Intent documents for matrix acidizing were not found in voluntary notices reported to the Chemical Disclosure Registry for hydraulic fracturing treatments (Table 2.4-2).

Table 2.4-2. Seven compounds submitted to DOGGR in a Notice of Intent to perform matrix acidizing that were publicly available between December 2013 and June 2014 that were not found in voluntary notices reported for hydraulic fracturing to the FracFocus Chemical Disclosure Registry (Table 2.A-1). Notices of Intent are required for all well stimulation treatments as of December 2013 under interim regulations.

Chemical Name	CASRN	Also reported as used in hydraulic fracturing (Table 2.A-1)
Hydroxylamine hydrochloride	5470-11-1	No
Benzaldehyde	100-52-7	No
Cinnamaldehyde	104-55-2	No
Amine oxides, cocoalkyldimethyl	61788-90-7	No
Copper dichloride	7447-39-4	No
Ethylene oxide	75-21-8	No
Sodium iodide	7681-82-5	No

As of January 2014, under SB 4, DOGGR has also required operators to submit a "Well Stimulation Treatment Disclosure Report" within 60 days of completion of well stimulation treatments, including matrix acidizing. These reports include a list of chemicals that were actually used in a well stimulation treatment. Analysis of the

disclosure reports available as of May 2015 identified 25 chemical compounds by CASRN used in matrix acidizing that were not found in the voluntary notices reported to the Chemical Disclosure Registry between 2011 and June 2014 (Table 2.4-3). However, of the 25 compounds identified as being used in matrix acidizing, 11 are also reported in the DOGGR disclosure reports as being used for hydraulic fracturing in 2015. Of the seven compounds submitted to DOGGR in the Notices of Intent for matrix acidizing (Table 2.4-2) that were not reported to the Chemical Disclosure Registry, only three were reported in the Well Stimulation Treatment Disclosure Reports. These results indicate that there is overlap in chemical use between matrix acidizing and hydraulic fracturing, and that mandatory reporting will include some chemicals not listed on voluntary disclosures prior to 2014.

Table 2.4-3. Chemicals used for matrix acidizing in California, as reported in DOGGR's Well Stimulation Treatment Disclosure Reports prior to May 5, 2015 that were not reported for hydraulic fracturing in the FracFocus Chemical Disclosure Registry (Appendix A, Table 2.A-1). Well Stimulation Treatment Disclosure Reports are required within 60 days of cessation of well stimulation treatment under SB 4.

Chemical Name	CASRN	Also reported as used in hydraulic fracturing in DOGGR's Disclosure Reports
1-Eicosene	3452-07-1	Yes
Hydroxylamine hydrochloride	5470-11-1	No
Acetaldol	107-89-1	No
1-Tetradecene	1120-36-1	Yes
1-Octadecene	112-88-9	Yes
Ammonium fluoride	12125-01-8	Yes
Benzyldimethylammonium chloride	122-18-9	Yes
Lauryl hydroxysultaine	13197-76-7	Yes
Benzododecinium chloride	139-07-1	Yes
Miristalkonium chloride	139-08-2	Yes
Nitrilotriacetic acid	139-13-9	No
Fatty acids, C18-unsatd., dimers	61788-89-4	No
Amines, hydrogenated tallow alkyl, acetates	61790-59-8	Yes
1-Hexadecene	629-73-2	Yes
Benzoic acid	65-85-0	No
Poly(oxy-1,2-ethanediyl), alpha-(nonylphenyl)-omega-hydroxy-, branched, phosphates	68412-53-3	No
Benzenesulfonic acid, C10-16-alkyl derivs., compds. with 2-propanamine	68584-24-7	Yes
Benzenesulfonic acid, C10-16-alkyl derivs., compds. with triethanolamine	68584-25-8	Yes
Copper dichloride	7447-39-4	No
Ethylene oxide	75-21-8	Yes

Chemical Name	CASRN	Also reported as used in hydraulic fracturing in DOGGR's Disclosure Reports
Potassium iodide	7681-11-0	No
Nitrogen	7727-37-9	No
Calcium phosphate, tribasic	7758-87-4	Yes
Aluminum chloride	7784-13-6	No
1,3-Propanediaminium, 2-hydroxy-N,N,N,N',N'-pentamethyl-N'-(3-((2-methyl-1-oxo-2-propenyl) amino)propyl)-, dichloride, homopolymer	86706-87-8	No

As of June 2013, SCAQMD, which regulates air quality in the Los Angeles Basin, has required operators to report information on chemical use for well drilling, completion, and rework operations. Reports from June 2013 through May 2014 were examined for treatments and operations that used hydrochloric acid; it was found that over 70 other chemical compounds identified by CASRN were used in conjunction with hydrochloric acid, according to these mandated reports. Over 20 compounds were identified from this list that were not found in the voluntary notices reported to the Chemical Disclosure Registry (Table 2.A-4).

A full analysis of the environmental risks associated with the use of acid and associated chemicals, such as corrosion inhibitors, requires a more complete disclosure of chemical use. Many of the same chemicals that are used for hydraulic fracturing are also used for matrix acidizing and other acid applications. Concerns specific to matrix acidizing, that may or may not apply to other well maintenance activities or hydraulic fracturing, include the dissolution and mobilization of naturally occurring heavy metals and other pollutants from the oil-bearing formation. The significance of this risk, if any, cannot be evaluated without a more complete understanding of the chemicals being injected and of the fate and effect of well stimulation fluids in the subsurface. The composition of the fluids returning to the surface as return flows and produced water needs to be better understood (Section 2.5).

2.4.4. Characterization of Chemical Additives in Well Stimulation Fluids

2.4.4.1. Characterization by Additive Function

Chemicals added to well stimulation fluids have a variety of purposes, including thickening agents to keep sand and other proppants in suspension (e.g., gels and crosslinkers) and chemicals (breakers) added at the end of treatments to remove thickening agents, leaving the proppant to hold open the newly created fractures (King, 2012; Stringfellow et al., 2014). Table 2.4-4 lists chemical use by function, where the function could be positively identified. It is apparent that treatments using gels and cross-linking agents are more common in California than treatments using friction reducers (Table 2.4-4). In other regions of the country where stimulation is used for

gas production, friction reducers (slicking agents) are commonly used (King, 2012; Stringfellow et al., 2014; U.S. EPA, 2015a). Over 80% of the treatments use an identified biocide and many formulations also include chemicals such as clay control additives. More information on the purposes of various chemicals used in hydraulic fracturing can be found elsewhere (King, 2012; Stringfellow et al., 2014; U.S. EPA, 2015a).

Disclosures frequently include descriptions of the purpose of the chemical added to well stimulation fluid. In the voluntary disclosures examined as part of this study, it was determined that the information entered for the purpose was very frequently inaccurate or misleading. In many cases, the purpose of the chemical additive is obscured because the disclosure reports list multiple purposes for each chemical disclosed. In other cases, the disclosed purposes are obviously incorrect. Impurities are typically not identified as such, and are instead given the same purpose description as the active ingredient in the chemical product. A more transparent explanation of the purpose of each chemical additive would contribute to a better understanding of the risks associated with well stimulation fluids.

Table 2.4-4. Hydraulic fracturing chemical use in California by function, where function was positively identified. This analysis was based on all records (N=45,058), consisting of 1,623 hydraulic fracturing treatments.

Function	Chemicals used for each function	Treatments using chemicals with this function
Breaker	11	1,599
Proppant	20	1,598
Gelling Agent	2	1,593
Carrier	23	1,515
Crosslinker	13	1,405
Biocide	10	1,392
Clay Control	7	1,184
Scale Inhibitor	10	865
Corrosion Inhibitor	8	182
Iron Control	2	60
Friction Reducer	1	13
Diverting Agent	3	10
Antifoam	1	6

2.4.4.2. Characterization by Frequency of Use

Although there are a large number of chemical additives used in well stimulation fluid (Appendix A, Table 2.A-1), the reported frequency of use of these compounds varies. As part of an environmental and hazard evaluation involving such an extensive list of chemicals, it is necessary to set priorities for which chemicals to evaluate first. Although any individual chemical use is potentially important, it is not practical to evaluate

all chemicals simultaneously. In this study, we use frequency of use as one of several parameters (including toxicity and amount used) for recommending specific chemicals for priority evaluation. The more frequently a chemical is used, the more likely any associated hazard, if any, could become an environmental or health risk.

Table 2.4-5 lists the 20 reported additives used most frequently in California. This list excludes proppants (e.g., quartz), bulk fluids (e.g., water), and diatomaceous earth, which is added as a stabilizer or carrier to biocides and other active ingredients (Greene and Lu, 2010). Frequently used chemicals on the list include gels and cross-linkers (e.g., guar gum, boron sodium oxide), biocides (e.g., 5-chloro-2-methyl-3(2H)-isothiazolone), breakers (e.g., ammonium persulfate, enzymes), and other treatment additives. Additives in Table 2.4-5 include solvents and a clay stabilizer. As discussed previously, reporting of chemical use is not mandatory, but the most frequently reported chemicals (Table 2.4-5) are in alignment with what is expected from other lines of inquiry and reported literature (e.g., Stringfellow et al., 2014; U.S. EPA, 2004).

Table 2.4-5. Twenty most commonly reported hydraulic fracturing components in California, excluding base fluids (e.g., water and brines) and inert mineral proppants and carriers. This analysis was based on all records (N=45,058), consisting of 1,623 hydraulic fracturing treatments.

Chemical	CASRN	Treatments using this chemical
Guar gum	9000-30-0	1,572
Ammonium persulfate	7727-54-0	1,373
Sodium hydroxide	1310-73-2	1,338
Ethylene glycol	107-21-1	1,227
2-Methyl-3(2H)-isothiazolone	2682-20-4	1,187
Magnesium chloride	7786-30-3	1,187
Magnesium nitrate	10377-60-3	1,187
5-Chloro-2-methyl-3(2H)-isothiazolone	26172-55-4	1,184
Isotridecanol, ethoxylated	9043-30-5	1,171
Hydrotreated light petroleum distillate	64742-47-8	1,167
Distillates, petroleum, hydrotreated light paraffinic	64742-55-8	1,129
2-Butoxypropan-1-ol	15821-83-7	1,119
Hemicellulase enzyme	9025-56-3	1,098
1,2-Ethanediaminium, N1,N2-bis[2-[bis(2-hydroxyethyl)methylammonio]ethyl]-N1,N2-bis(2-hydroxyethyl)-N1,N2-dimethyl-, chloride (1:4)	138879-94-4	1,076
1-Butoxypropan-2-ol	5131-66-8	973
Phosphonic acid	13598-36-2	790
Amino alkyl phosphonic acid	Proprietary	668
Boron sodium oxide	1330-43-4	666
Sodium tetraborate decahydrate	1303-96-4	520
Enzyme G	Proprietary	480

In Appendix A, Table 2.A-5 contains a list of the approximately 150 chemical additives that were reported less than ten times in 1,623 applications. From a search of product literature, patents, and scientific literature, it can be determined with some certainty that many of the compounds in Table 2.A-5 are impurities (e.g., sodium sulfite), but many are clearly specific products applied for the purpose of well stimulation (e.g., FRW-16A, which is a stimulation fluid additive sold by Baker Hughes). Although the voluntary reporting indicates that these compounds are not widely used in California, the lack of mandatory reporting means that the frequency of use of these chemicals cannot be determined with certainty. Based on our analysis that the voluntary disclosure regime appears to produce representative data, we conclude that the additives that are reported less frequently (Table 2.A-5) deserve a lower priority for a complete risk analysis than compounds that are used more frequently (e.g., Table 2.4-5).

2.4.4.3. Characterization by Amount of Materials Used

Another criterion for selecting priority chemicals for a more thorough evaluation is the amount of material that is used. The concentrations for chemical additives that are used in median quantities greater than 200 kg (440 lbs) per hydraulic fracturing treatment are compiled in Appendix A, Table 2.A-6. This table does not include base fluids (water, saline solutions, or brine), which can account for over 85% of the mass of the well stimulation fluid. As would be expected, at least nine of the compounds in Table 2.A-6 (Appendix A) are proppants and many are solvents, crosslinkers, gels, and surfactants. Since the compounds listed in Table 2.A-6 (Appendix A) are used in significant amounts, they are considered to be priority compounds that warrant further investigation.

2.4.4.4. Characterization by Environmental Toxicity

For assessing environmental toxicity, aquatic species are typically exposed to varying concentrations of chemicals under controlled conditions and, after a specified time, the test species are examined for acute or chronic effects (U.S. EPA, 1994; OECD, 2013). Toxicity to the environment is inferred from tests against a variety of aquatic species that fall into the categories of fish, crustaceans, and aquatic plants, usually represented by algae. In these studies, the test animal is exposed to high concentrations of the test chemical, and the survival or health of the animals as a function of the exposure is determined, with the most common acute metric being the concentration at which 50% of the test population is expected to be adversely effected or dies, if the endpoint is lethality (see methods section). Since aquatic toxicity tests are highly standardized, the results can be used to compare and contrast industrial chemicals (Stringfellow et al., 2014).

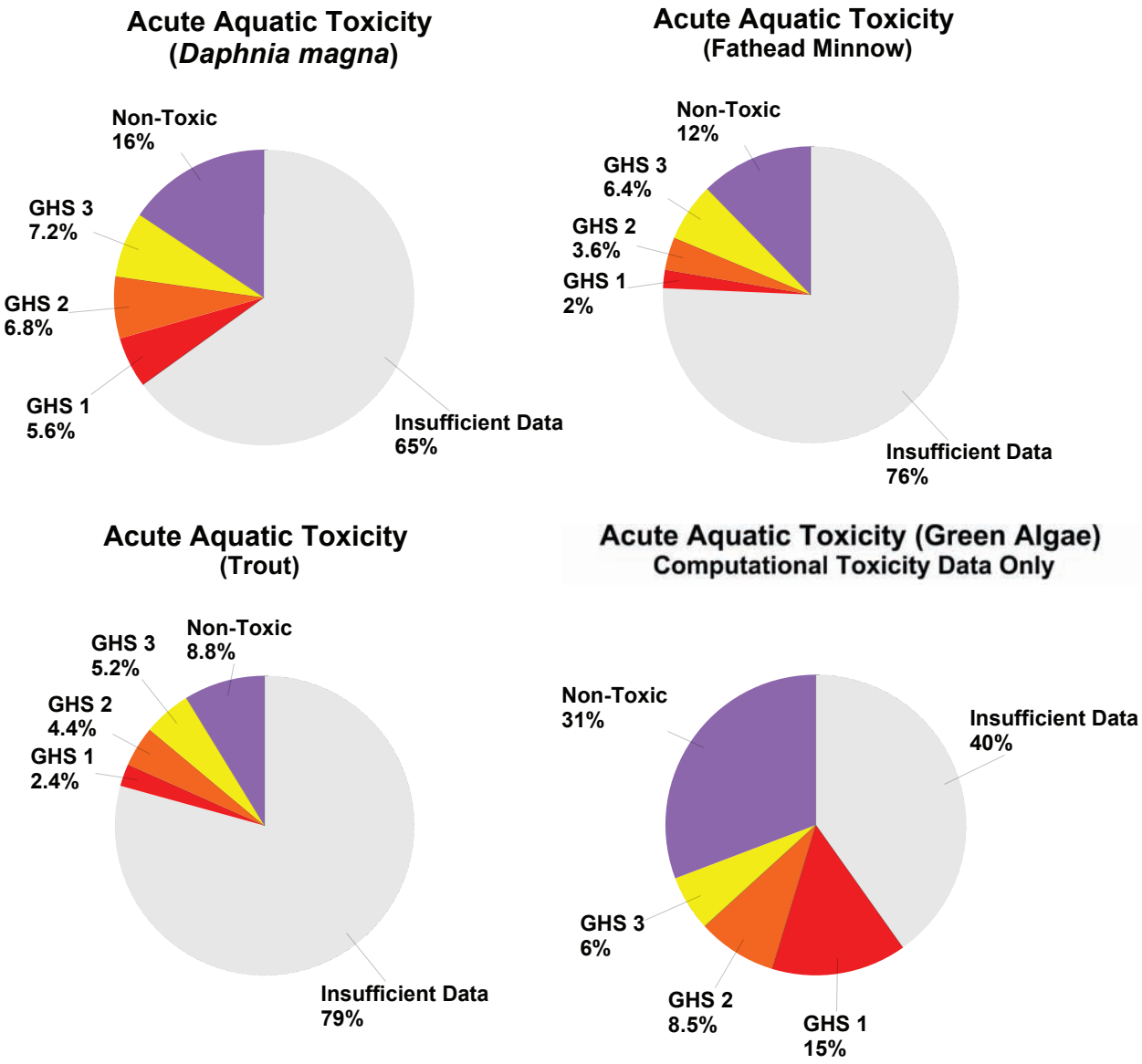


Figure 2.4-2. Aquatic toxicity data for all hydraulic fracturing and acid treatment chemicals. Chemical toxicity was categorized according to United Nations standards in the Globally Harmonized System of Classification and Labeling of Chemicals (GHS), which classifies acute toxicity for aquatic species on a scale of 1 to 3, with 3 being the least toxic.

An overview analysis of the experimental results for acute aquatic toxicity tests are presented in Figure 2.4-2. Thirty-three chemicals have a GHS ranking of 1 or 2 for at least one aquatic species (Table 2.A-7), indicating they are hazardous to aquatic species and could present a risk to the environment if released. Species for which toxicity data were collected are *Daphnia magna*, fathead minnows, and trout. The most toxic chemical additives for these aquatic organisms are shown in Table 2.4-6. Significant data gaps

exist for aquatic species testing. *Daphnia magna* toxicity data are missing for 65% of the chemical additives identified by CASRN, fathead minnow toxicity data are missing for 76%, and trout data are missing for 79% of chemicals (Figure 2.4-2). EPI Suite estimations for green algae toxicity are missing for 40% of the chemicals (Figure 2.4-2).

Table 2.4-6. The most toxic hydraulic fracturing chemical additives used in California with respect to acute aquatic toxicity, based on the United Nations Globally Harmonized System (GHS) of Classification and Labeling of Chemicals system. Lower numbers indicate higher toxicity, with a designation of "1" indicating the most toxic compounds. Results are only shown for chemicals with GHS rating of 1 for any of the aquatic organisms in the analysis (Daphnia magna, fathead minnows, and trout).

Chemical Name	CASRN	GHS rating
2-Propenoic acid, ammonium salt (1:1), polymer with 2-propenamide	26100-47-0	1
2,2-dibromo-3-nitrilopropionamide	10222-01-2	1
2-Methyl-3(2H)-isothiazolone	2682-20-4	1
5-Chloro-2-methyl-3(2H)-isothiazolone	26172-55-4	1
Alcohols, C10-16, ethoxylated	68002-97-1	1
Alcohols, C12-13, ethoxylated	66455-14-9	1
Alkyl dimethylbenzyl ammonium chloride	68424-85-1	1
Chlorous acid, sodium salt (1:1)	7758-19-2	1
Ethoxylated C14-15 alcohols	68951-67-7	1
Glutaraldehyde	111-30-8	1
Hydrochloric acid	7647-01-0	1
Naphthalene	91-20-3	1
Quaternary ammonium chloride, benzylcoco alkyldimethyl, chlorides	61789-71-7	1
Solvent naphtha, petroleum, heavy arom.	64742-94-5	1

It is important to note that acute toxicity levels of many compounds from EPA standard tests of *Pimephales promelus* (fathead minnow) should be interpreted with caution, since they may differ from the sensitivity of California species. We examined relative toxicity (mortality) of a common well stimulation additive in a comparison between California freshwater fish and *Daphnia* and minnow species (Table 2.4-7). Several observations were made, including that (1) toxicity can vary by more than an order of magnitude among fish species, and (2) in almost all cases, fathead minnow was more resistant to the QAC than other California resident species. These data underscore the need to perform standardized toxicity tests with individual well stimulation chemicals and mixtures of well stimulation chemicals against California species, as well as standard test organisms. Additionally, toxicity will differ by life history stage, and many embryos or larvae may show much higher sensitivity to chemicals than adults, further illustrating that standard acute toxicity tests are just a first step in a more complete evaluation of chemicals (U.S. EPA, 2011).

The aquatic toxicity tests reviewed in this report describe the effects that varying concentrations of pure chemicals have on aquatic species, and are most applicable to effluents and other discharges released directly to surface waters. In the context of normal operations during well stimulation treatments, chemicals are injected in the subsurface, where they can interact with subsurface minerals and otherwise undergo chemical reactions before potentially contacting groundwater or surface water. For example, acids injected into formation rock react rapidly, and the acidity of the injected fluid diminishes quickly. Therefore, any comparison made between the concentrations assessed in toxicity tests and the concentrations reported in well stimulation fluids need to account for the fact that well stimulation fluids will typically be diluted and altered prior to any potential contact with either groundwater or surface water. Further study is required to understand how well stimulation fluids are altered as they interact with surrounding formation rock, and gaining knowledge of these chemical transformations needs to be an essential component of future risk assessment studies for unconventional oil and gas development.

Table 2.4-7. Comparison of results between standard test organisms and California native and resident species. Shown is a comparison of the lethal concentration to 50% of test organisms (LC_{50}) values across different aquatic species towards a common quaternary ammonium compound (QAC) used in hydraulic fracturing fluids. If different LC_{50} values for the same experimental conditions were present in the EPA's Pesticide Ecotoxicity Database, a range of test concentrations was noted. In addition, some experiments had different exposure duration when the effect was observed, leading to lower LC_{50} values with increasing exposure duration e.g., for the striped bass. (U.S. EPA and Office of Pesticide Programs, 2013; Bills et al., 1993; Krzeminski et al., 1977).

Species	Alkyl dimethylbenzyl ammonium chloride CASRN 68424-85-1 LC_{50} or EC_{50} ($\mu g\ L^{-1}$)
Water Flea (*Daphnia magna*)[1]	37–158
Fathead Minnow (*Pimephales promelas*)	280–1,400
Bluegill (*Lepomis macrochirus*)	68–5,300
Rainbow Trout (*Oncorhynchus mykiss*)[2]	64–7,690
Brown Bullhead (*Ameiurus nebulosus*)	1,590
Green Sunfish (*Lepomis cyanellus*)	2,250
Redear Sunfish (*Lepomis microlophus*)	740
Smallmouth Bass (*Micropterus dolomieu*)	1,370
Largemouth Bass (*Micropterus salmoides*)	1,130
Striped Bass (*Morone saxatilis*)	2,820–14,200
Channel Catfish (*Ictalurus punctatus*)	980
Brown Trout (*Salmo trutta*)	1,950
Lake Trout (*Salvelinus namaycush*)	420
Goldfish (*Carassius auratus*)	1,490

[1]In the case of Daphnia magna, results are reported as effective concentration where 50% of the test population is immobilized at the indicated concentration (EC_{50}). For all other species, the results are measured as mortality (LC_{50}).

[2]Native California species, all other fish are non-native resident species.

2.4.5. Selection of Priority Chemicals for Evaluation Based on Use and Environmental Toxicity

Identification of priority chemical additives for further investigation is an important step toward a complete understanding of the potential direct impacts of hydraulic fracturing and other well stimulation treatments. Using the information and analysis discussed above, we can develop a proposed list of priority chemical additives, based on toxicity and mass used (Appendix A, Table 2.A-8). Chemicals on this list were ranked and given a "Tox Code," representing the highest toxicity ranking the compound received under the GHS system for any environmental toxicity test using aquatic species. The Tox Code was combined with the analysis of the mass of chemical used per well stimulation treatment to allow better synthesis of information (Appendix A, Table 2.A-8). In Chapter 6, a similar approach is taken for the ranking of chemicals in the context of public health and expanded to create a human-health-hazard screening index and includes other impact factors in addition to toxicity and mass of chemical used.

The chemicals list in Table 2.A-8 represent the "known knowns," namely chemicals for which we have a CASRN and some level of toxicity information. In addition to the evaluation of these chemicals, we need to consider the "known unknowns," that for the majority of chemicals identified by CASRN we do not have sufficient toxicological information for characterization (Figures 2.4-2, Appendix B, 2.B-1, and 2.B-2). In addition, there are the "unknown unknowns," represented by the large number of chemicals (discussed below) that are not identified by CASRN (Appendix A, Table 2.A-9) and the large number of well stimulation treatments for which no information was reported under the voluntary disclosure system.

2.4.6. Chemical Additives with Insufficient Information to be Fully Characterized

Over 100 of the materials listed in Table 2.A-1 (see Appendix A) are identified by non-specific names and are reported as trade secrets, confidential business information, or proprietary information (Appendix A, Table 2.A-9). These materials cannot be evaluated for hazard, risk, and environmental impact without more specific identification. Chemical additives that are not identified by CASRN cannot be conclusively identified and cannot be fully evaluated. As can be seen from Tables 2.A-1 and 2.A-6, many of these unidentified or poorly identified compounds are used frequently or in significant amounts for well stimulation. Without complete identifying information, it is not possible to know if more than one chemical (a chemical mixture) is being reported using the same common name. Therefore, 100 chemicals could be the minimum number of completely unknown materials. Additives that were not identified by CASRN were not included in the hazard analysis discussed below.

Undefined chemicals should not be ignored, and some hazard information can be inferred from the reported common names. For example, the common names "oxyalkylated amine quat," "oxyalkylated amine," "quaternary amine," and "quaternary ammonium compound"

all indicate that these additives fall into the category of quaternary ammonium compounds (QACs). Similarly, many of the general names suggest that the proprietary additives are surfactants (e.g., "ethoxylated alcohol," "surfactant mixture," etc.) that are widely used in the industry. Surfactants and QACs have broad application in both industry and household use, and QACs can be used as biocides (Kreuzinger et al., 2007; Sarkar et al., 2010). The environmental hazard associated with an individual surfactant or QAC is highly variable, and some QACs can be persistent in the environment (e.g., Garcia et al., 2001; U.S. EPA, 2006a; 2006b; Davis et al., 1992; Arugonda, 1999). In other disclosures, surfactants and QACs used for well stimulation are identified by CASRN, and evaluation of those chemicals can be used to give insight into the hazard associated with proprietary chemicals used for the same purpose.

2.4.7. Other Environmental Hazards of Well Stimulation Fluid Additives

In this report, we performed a hazard assessment of chemicals for which adequate information was available. A hazard is any biological, chemical, mechanical, environmental, or physical agent that is reasonably likely to cause harm or damage to humans, other organisms, or the environment in the absence of its control (Sperber, 2001). A chemical can be considered a hazard if it can potentially cause harm or danger to humans, property, or the environment because of its intrinsic properties (Jones, 1992).

The identification of hazards (or the lack thereof) is the first step in performing risk assessments. Once the hazards are established or defined, then the more involved process of risk assessment can begin. In contrast to hazard, risk includes the probability of a given hazard to cause a particular loss or damage (Alexander, 2000). It is important to note that it was beyond the scope of this study to perform a risk assessment, and that there are extensive data gaps on the chemical mixtures and environmental exposures that need to be addressed to enable future risk assessments. In addition, many of the materials listed in Appendix A, Table 2.A-1 are reactive and are expected to react with one another and/or other materials within the well and mineral formation. These byproducts could be more or less hazardous than the parent compounds examined here. Byproducts are not measured or reported, and thus could not be evaluated here.

2.4.7.1. Chronic and Sublethal Effects of Chemicals

In this chapter, the analysis of potential impacts from chemicals used in well stimulation fluids has focused on acute lethality to aquatic organisms. However, sublethal impacts from acute or chronic exposures are often related to individual survival potential and population viability (U.S. EPA, 1998). Impacts on reproduction and development are directly linked to population viability. Physiological status, disease or debilitation, avoidance behavior, and migratory behavior are identified as important to population viability in the U.S. Environmental Protection Agency's Generic Ecological Assessment Endpoints (U.S. EPA, 2003).

Lack of data on chronic and sublethal impacts of chemicals used in well stimulation treatments represents a critical data gap in the analysis of potential ecological impacts of unconventional oil and gas development in California. However, the limited data available indicate that sublethal impacts may occur. Exposure to the biocide 2,2-dibromo-3-nitrilopropionamide (DBNPA) negatively impacts aquatic organisms at concentrations well below lethal levels. Growth of juvenile trout was impaired after 14 days exposure to 0.04 mg L^{-1} DBNPA (Chen, 2012). The same study showed impaired reproduction in aquatic invertebrates at 0.05 mg L^{-1} (Daphnia magna). *Xenopus laevis* tadpoles exposed to sublethal concentrations of the biocide methylisothiazolinone (MIT) during development showed several neurological deficits affecting behavior and susceptibility to seizures (Spawn and Aizenman, 2012). Chronic sublethal exposure to the surfactants linear alkylbenzene sulfonates (e.g., dodecylbenzene sulfonic acid) can impact the gills and olfactory system of fish (Zeni and Stagni, 2002; Asok et al., 2012) and decrease reproduction in invertebrates (da Silva Coelho and Rocha, 2010). More information is needed to assess the potential chronic and/or sublethal impacts of well stimulation fluids on aquatic species.

2.4.7.2. Environmental Persistence

The risk associated with a given chemical depends on how long the chemical persists in the environment. A toxic compound released into the environment that decays rapidly presents less chance for exposure to occur, damage to be inflicted, and risk to be accumulated. The list of chemicals used in hydraulic fracturing (Table 2.A-1) includes some compounds that could be environmentally persistent. For example, many of the chemical additives are surfactants and related compounds such as QACs. Persistence of surfactants and QACs is directly related to hydrocarbon chain length and other structural properties, with high molecular weight constituents likely to be the least volatile and most slowly degraded by microbes (Garcia et al., 2001; Kreuzinger et al., 2007; HERA, 2009; Li and Brownawell, 2010; Sarkar et al., 2010; Jing et al., 2012). Other compounds that may persist in the environment include the halogenated biocides DNBPA and MBNPA (2-bromo-3-nitrilopropionamide) and copper-EDTA (ethylenediaminetetraacetic acid).

A complete investigation of persistent pollutants found in well stimulation fluid is beyond the scope of this study, but this preliminary analysis suggests that potentially persistent pollutants and the reaction products of well stimulation fluid should be evaluated. Baseline measurements for current environmental levels of these compounds, including concentrations in biota as appropriate, are needed in order to determine whether or not these levels are altered by future exposure to well stimulation fluid.

A major mechanism for environmental attenuation of chemicals is biodegradation. Biodegradation in nature or in engineered treatment facilities removes chemicals from environmental systems. Biodegradable materials do not typically persist in the environment, regardless of whether they are released by accident or on purpose.

Standardized methods to measure the biodegradation potential allow the comparison and ranking of chemicals (OECD, 2013; U.S. EPA, 2011). Biodegradation tests only apply to organic compounds. The percentages of chemicals, which have been tested under standardized OECD test conditions and found to be biodegradable, not biodegradable, or for which biodegradation information is unknown, are shown in Figure 2.4-3. The "biodegradable" category includes all chemicals that are ranked as inherently or readily biodegradable by OECD protocols (OECD, 2013). The majority of chemicals that have been tested are biodegradable and therefore are not expected to persist in the environment (Figure 2.4-3). However, approximately one-half of the organic compounds identified by CASRN have not been tested for biodegradation by standardized methods, and many more compounds not identified by CASRN cannot be evaluated. Additionally, standardized biodegradation tests do not take into account chemical interactions that may occur, such as how the presence of biocides may affect the degradation of otherwise biodegradable compounds. Overall, it can be concluded that there is insufficient information to predict how these chemical mixtures will persist in the environment.

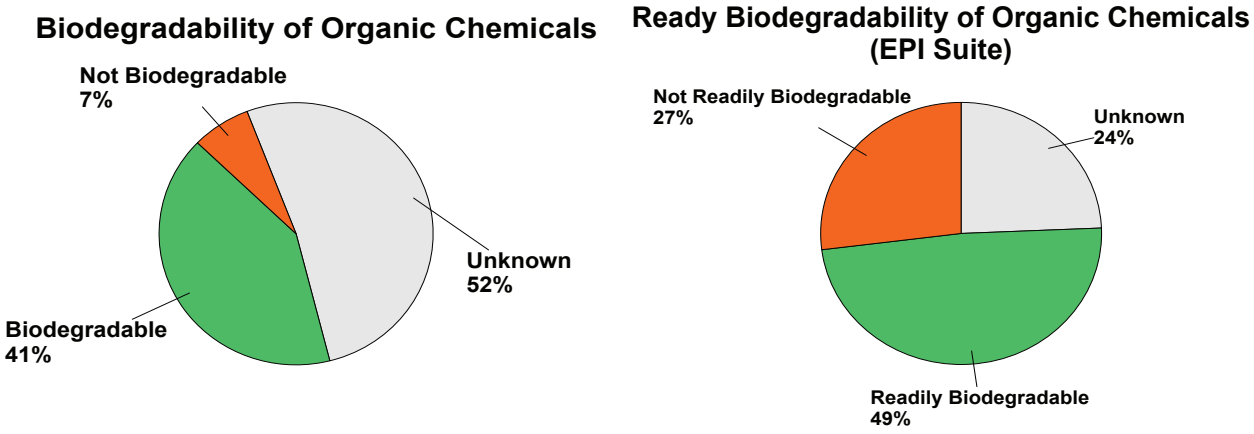


Figure 2.4-3. Biodegradability of chemicals. For pie charts containing both experimental and computational biodegradability data, the experimental data was used as the value for that chemical in the creation of the pie chart. If only computational data was available, the computational value was used. Computational results are generated for the U.S. EPA BIOWIN program which are not considered as reliable or accurate as experimental results (U.S. EPA, 2012b).

2.4.7.3. Bioaccumulation

Given the large numbers of compounds used in well-stimulation treatments, it is possible that some compounds or reaction products of those chemicals will persist in the environment. Compounds that persist in the environment present a greater risk, if released, than readily degradable compounds. Some persistent compounds may have the potential to "bioaccumulate" or become more concentrated in organisms than in the environment. This is particularly important for organisms higher up on the trophic food chain, such as humans. Trophic transfer of chemicals that bioaccumulate in exposed

organisms to higher concentrations of a chemical, or its transformation products, than are found in the environment are an important exposure mechanism in ecological systems (Currie et al., 1997; Clements and Newman, 2006; Maul et al., 2006; Wallberg et al., 2001; Zhang et al., 2011).

Bioaccumulation is driven by contaminant uptake, distribution, metabolism, storage, and excretion (Connell, 1988; Mackay and Fraser, 2000). The potential for a chemical to bioaccumulate can be indicated by its physiochemical characteristics, such as the octanol-to-water partition coefficient (K_{ow}), which indicates the degree of lipophilicity. However, some chemicals may bioaccumulate despite physiochemical characteristics that indicate otherwise. Active transport of chemicals (Buesen et al., 2003) or the inhibition of efflux transporters (Smital and Kurelec, 1998) can also result in bioaccumulation. An analysis of all chemicals identified in this study indicated that characterization of octanol-to-water partition coefficients for these compounds has not been completed (Figure 2.4-4). Measurement of octanol-to-water partition coefficients and other basic physical and chemical characteristics, such as Henry's constants and sorption coefficients, are needed for development of a complete environmental profile of a chemical (Stringfellow et al. 2014; U.S. EPA 2011).

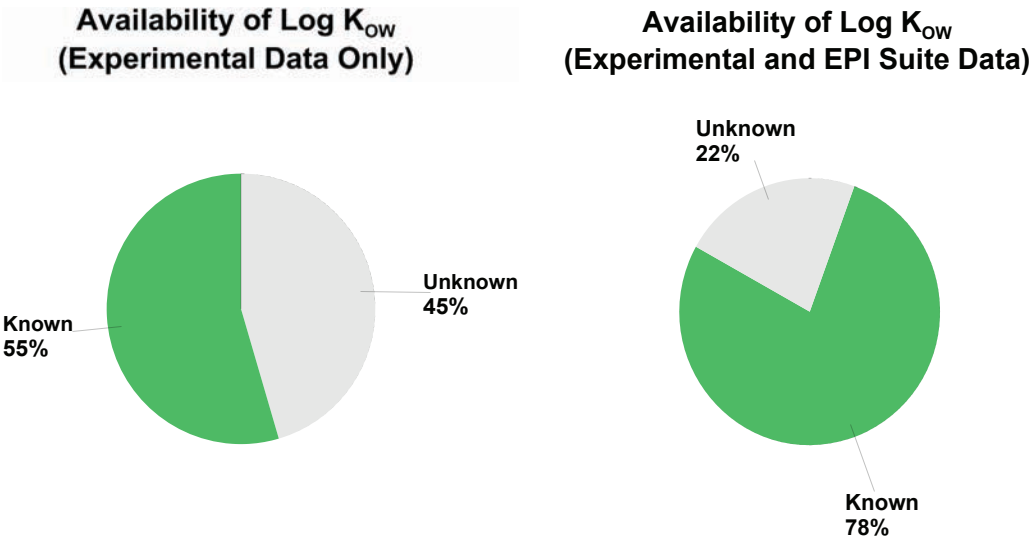
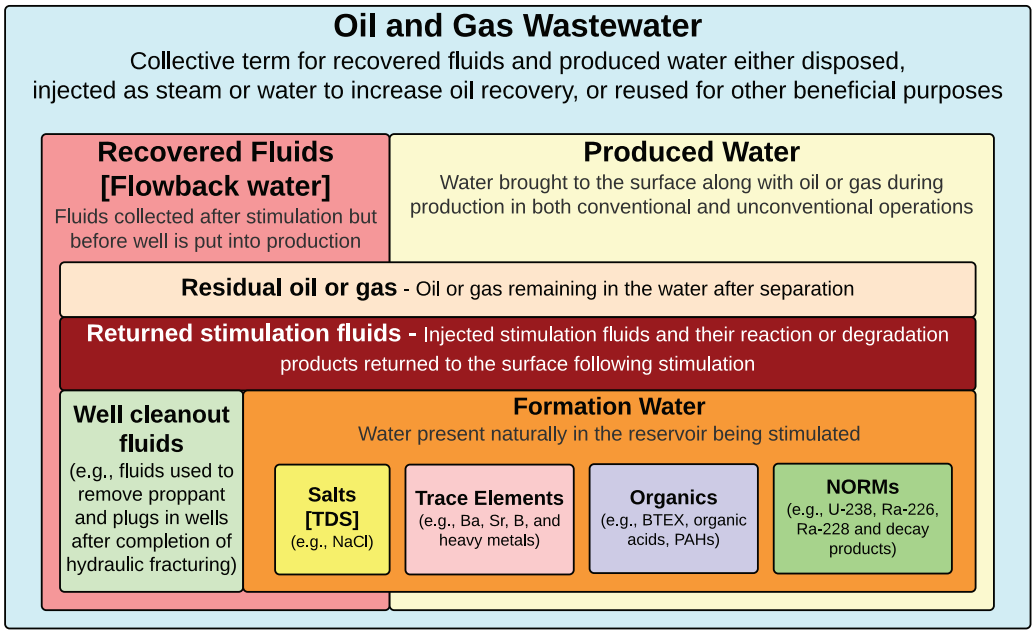


Figure 2.4-4. Availability of octanol-water partitioning measurements for hydraulic fracturing and acid treatment chemicals. The potential for a chemical to bioaccumulate can be indicated by its physiochemical characteristics, such as the octanol-to-water partition coefficient (K_{ow}) which indicates the degree of lipophilicity. Physical data such as octanol-to-water partition coefficients are needed to create a complete environmental profile on a chemical. Computational results are not considered as reliable or accurate as experimental results.

2.5. Wastewater Characterization and Management

2.5.1. Overview of Oil and Gas Wastewaters

Both stimulated and non-stimulated wells generate water as part of oil and gas production over the lifetime of the wells. This water byproduct is referred to as "produced water," which consists of formation water mixed with oil and gas that is brought to the surface during production. For stimulated wells, the additional term "flowback" is commonly used to describe the fluids recovered after the well pressure is reduced following stimulation, but *before* the well is put into production (Pavley, 2013; U.S. EPA, 2012a; Vidic et al., 2013). New California regulations introduce another term, "recovered fluids," which is defined as the water returned "following the well stimulation treatment that is not otherwise reported as produced water" (DOGGR, 2014e). The U.S. EPA (U.S. EPA, 2012a) and others use the term "wastewater" to refer to all fluids that return to the surface along with the oil and gas, including recovered fluids, flowback, and produced water. Figure 2.5-1 illustrates the complex nature of wastewater from unconventional oil and gas development.



*** Boxes are not drawn to scale and are separated for visual clarity.**

Figure 2.5-1. The water returned from stimulated wells in California consists of recovered fluids (i.e., flowback water) and produced water, which can be disposed of as wastewater or beneficially reused. The recovered fluids in California are typically generated in small quantities and can contain returned stimulation fluids, well cleanout fluids and formation water. The produced water consists primarily of formation water (also referred to as formation brines due to its high salt content), as well as some residual oil or gas, and an unknown amount of returned stimulation fluids. The concentrations and composition of the returned stimulation fluids in both the recovered fluids and produced water is currently unknown. Note that the boxes are not drawn to scale and are separated for visual clarity.

Wastewater from well stimulation operations can contain a variety of constituents, including (1) the additives pumped into the well during well stimulation; (2) compounds that formed due to transformation or degradation of the additives, or to chemical reactions between the additives; (3) dissolved substances from waters naturally present in the target geological formation; (4) substances mobilized from the target geological formation; and (5) some residual oil and gas (NYSDEC, 2011; Stepan et al., 2010). It is expected that the amount of stimulation fluids returned is highest immediately following well stimulation, with a decrease in concentration over time (Barbot et al., 2013; Clark et al., 2013; Haluszczak et al., 2013; King, 2012). The period during which returned stimulation fluids come to the surface following stimulation varies between and within a region, but can range from a few hours to several weeks in shale producing natural gas (Barbot et al., 2013; Hayes, 2009; Stepan et al., 2010; Warner et al., 2013b). Studies have not been conducted to determine the return period for simulation fluids used for oil production in diatomite, as found in California. It is likely that, in California, stimulation fluids, chemical additives, and their reaction byproducts will be present in the water returned to the surface after the well is put into production, and thus will be present in produced water.

New California monitoring and reporting requirements focus on testing and management of recovered fluids and do not require extensive measurement or monitoring of produced water, which is likely to contain some of the stimulation fluids and their degradation byproducts. A recent white paper from DOGGR notes “When well stimulation occurs, most of the fluid used in the stimulation is pumped to the surface along with the produced water, making separation of the stimulation fluids from the produced water impossible. The stimulation fluid is then co-disposed with the produced water” (DOGGR, 2013). The combined handling of wastewaters generated during unconventional oil and gas production makes collection of better data and full characterization of wastewaters over time an important component of understanding the environmental impacts of hydraulic fracturing. The lack of studies on these wastewaters is identified as a major day gap.

In this section, we summarize data available on the quantities and characteristics of wastewater generated from stimulated wells in California. In our analysis, we evaluate the following questions:

- What are the quantities of recovered and produced water generated from stimulated wells within the first few months following stimulation, and are these volumes different from the quantities of produced water generated by non-stimulated wells in California?

- What are the chemical compositions of recovered fluids and produced water from stimulated wells? Is produced water from stimulated wells compositionally different than produced water from non-stimulated wells?

- How are recovered and produced waters from stimulated wells managed, i.e., how are they handled onsite, treated, reused and/or disposed?

2.5.2. Recovered Fluids Generated from Stimulated Wells in California

Recovered fluids are the fluids that are returned to the surface *before* production commences. According to one California operator, the recovered fluids can be a mixture of water from the formation, returned stimulation fluids, and well clean-out fluids (pers. comm., Nick Besich, Aera Energy). Operators are required to disclose "the source, volume, and specific composition and disposition" of the recovered fluids in well completion reports submitted to DOGGR within 60 days following stimulation.

2.5.2.1. Quantities of Recovered Fluids

We determined the quantities of recovered fluids from 506 completion reports filed and posted as of December 15, 2014, for 499 hydraulic fracturing and seven matrix acidizing treatments (DOGGR, 2014a). We first compared the volume of recovered fluid from each well to the corresponding volume of injected stimulation fluids to estimate the maximum recovery of stimulation fluids during the initial phase of wastewater production. One well where the injected volume was reported as zero was excluded from this analysis. Actual recoveries are likely to be lower, but could not be calculated, since the concentrations or masses of stimulation fluid constituents in the recovered fluids are not measured. We also compared the volumes of recovered fluids to the produced water generated during the first month of production, for records where matching production data were available in the DOGGR Production database, to put the recovered fluid volumes in the context of total wastewater generated immediately after stimulation. Wells for which the production volume for the first month or the volume of recovered fluid were reported as zero have been excluded from this analysis.

The volumes of recovered fluids collected from both hydraulic fracturing and acid matrix treatments range from 0 to 1,600 m^3 (9,900 barrels) (Table 2.5-1). The recovered fluid volumes are small (mostly less than 5%) compared to the injected fluid volumes for hydraulic fracturing treatments (Figure 2.5-2). There were eighteen hydraulic fracturing treatments for which the recovered fluid volumes were reported as zero, which could either be errors or indicate that fluids were directly diverted into the production pipeline without capturing any recovered fluid. Hence, the recovered fluid is conclusively a small portion of the fluids injected as part of a hydraulic fracturing treatment. In contrast, the recovered fluids from matrix acidizing potentially represent a much larger fraction (50–70%) of the stimulated fluids for the matrix acidizing operations (Table 2.5-1). The actual recovery of returned stimulation fluids has not been investigated and would require chemical analysis to differentiate between returning well stimulation fluids and connate water. However, the actual recovery of returned well stimulation fluids is likely to be lesser than the reported volumes of recovered fluid, since the recovered fluids can also contain well cleanout fluids and formation water (Section 2.5.2.2).

Table 2.5-1. A comparison of total recovered fluid and injected fluid volumes for stimulated wells located throughout California, as reported in DOGGR completion reports as of Dec 15, 2014 (N=505). All numbers are rounded to two significant figures. St. dev. = standard deviation; min. = minimum, max. = maximum.

	Matrix Acidizing (N=7)			**Hydraulic fracturing (N=498)**	
	Recovered Volume m^3 (barrels)	Injected Volume m^3 (barrels)		Recovered Volume m^3 (barrels)	Injected Volume m^3 (barrels)
Median	150 (970)	240 (1,500)		11 (72)	300 (1,900)
Average	170 (1,100)	270 (1,700)		77 (480)	410 (2,600)
St. Dev.	71 (450)	100 (650)		240 (1,500)	420 (2,600)
Min.	84 (530)	150 (960)		0 (0)	37 (230)
Max.	290 (1,800)	430 (2,700)		1,600 (9,900)	2,600 (16,000)

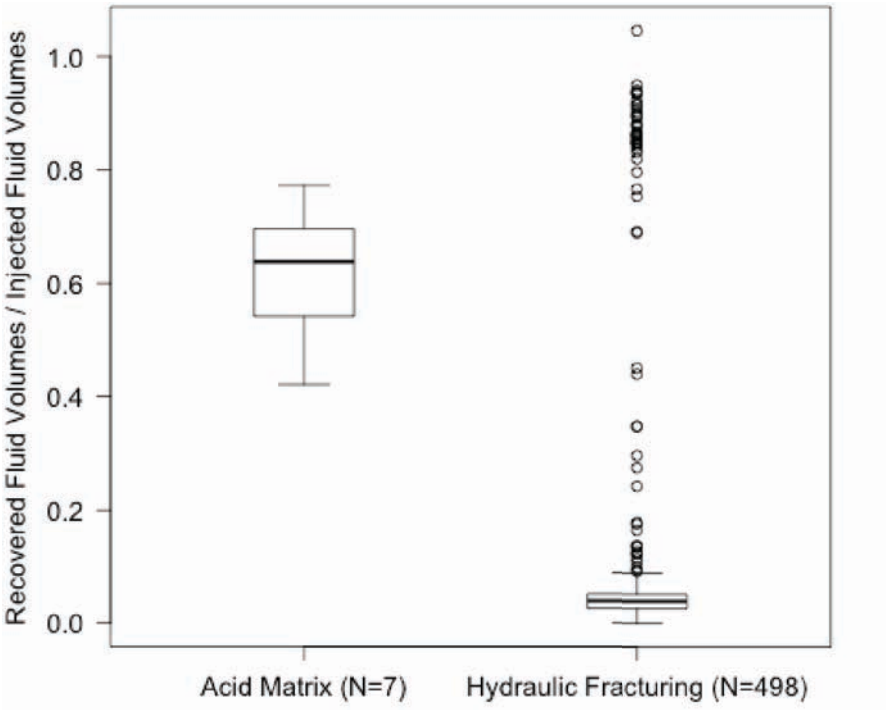


Figure 2.5-2. The fraction of recovered fluid volumes compared to the injected stimulation fluid volumes was significantly higher for acid matrix treatments (50-70%), when compared to hydraulic fracturing treatments. Typically, hydraulic fracturing treatments had very small recoveries (<5%), though there were many cases in which the recovered fluid volumes were much higher. Boxes show the 25th to 75th percentiles of the data, and the central lines show the median. Whiskers extend to 1.5 times the interquartile range from the box. The circles represent the outliers in the data. Data Source: DOGGR Completion reports as of Dec 15, 2015.

The recovered fluids were an extremely small fraction of wastewater generated within just the first month of production (Figure 2.5-3). The volume of produced water in the first month of operations was also substantially larger than the volumes of injected stimulation fluids for both hydraulic fracture and acid matrix treatments.

These analyses show that for hydraulic fracturing operations, the recovered fluids are a fraction of the amount of fluid injected, suggesting that produced water will likely contain some amount of fracturing fluids. Operators are currently required to only report chemical analysis results for the recovered fluids (Section 2.5.2.2), but there is no data available or reported about the masses of stimulation fluids (or their degradation byproducts) present in produced waters. The amount and fate of the injected fracturing fluids that is left behind in the subsurface is unknown.

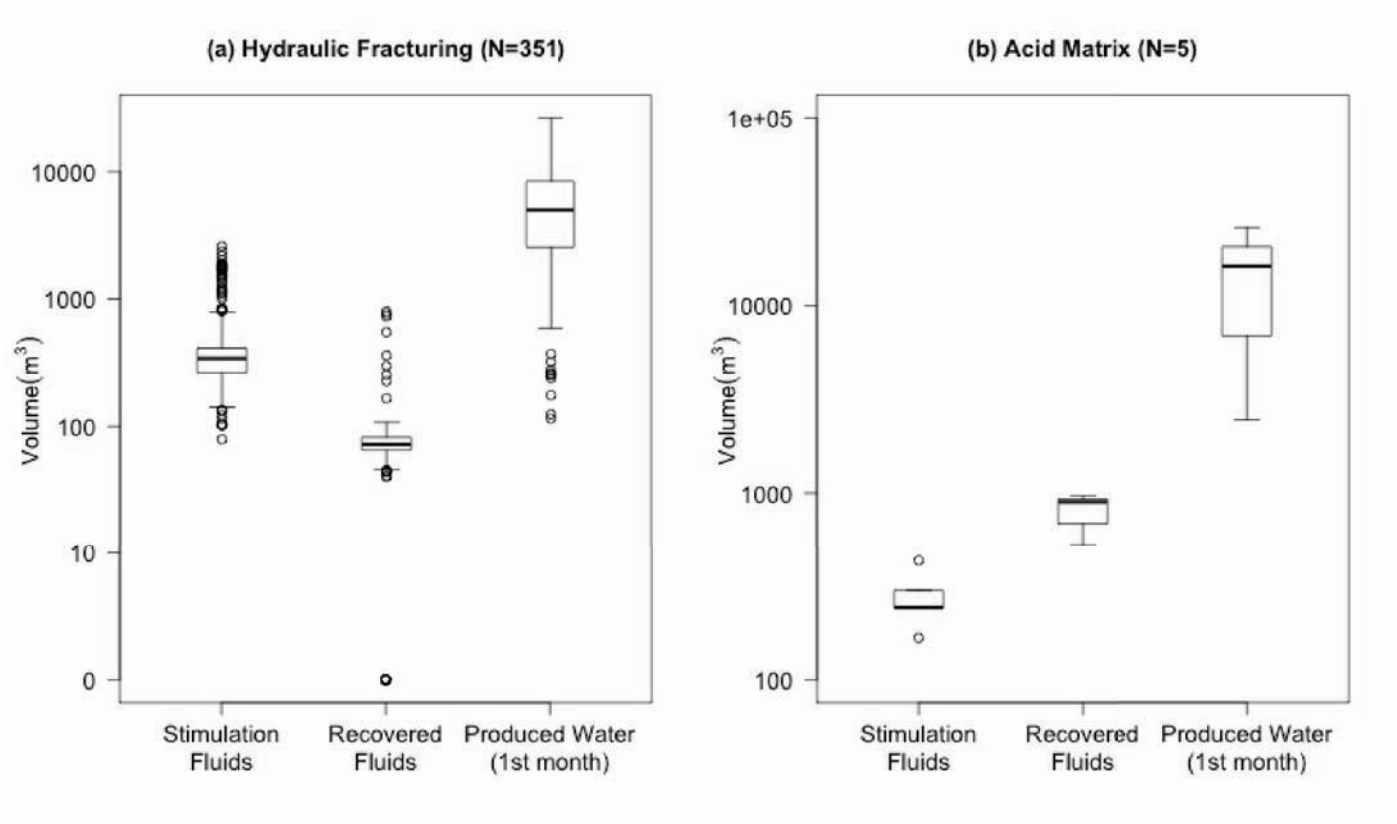


Figure 2.5-3. Volumes (log-scale) of injected fluids, recovered fluids, and produced water in the first month of production for (a) hydraulically fractured and (b) matrix acidizing treatments for wells that were reported in the DOGGR completion reports as of Dec 15, 2014 that had matching records in the DOGGR Production database. Wells that did not have any production within the first month were not considered in this analysis. Boxes show the 25th to 75th percentiles of the data, and the central lines show the median. Whiskers extend to 1.5 times the interquartile range from the box. The circles represent the outliers in the data.

Under new regulations, recovered fluids are now being characterized before disposal, and the results are included in well completion reports submitted to DOGGR. We investigated 45 laboratory chemical analyses that were submitted for onshore stimulated wells as of July, 2014. These data were made available as PDF files and represent waters recovered from operations in two fields (North and South Belridge) by one operator (Aera Energy). Operators are not required to report when the samples were collected after stimulation. According to the operator, the sample "is collected somewhere in the middle of recovery, but operationally that does not always happen." (Aera Energy, Appendix 2.F). Analyses include total carbohydrate, because the carbohydrate guar is a commonly used gelling agent in well stimulation, but this is the only stimulation additive for which a specific measurement was made. Other constituents that were measured include TDS, trace metals, organics, and naturally occurring radioactive materials (NORM) (Table 2.5-2).

Carbohydrates were detected in some of the recovered fluids, suggesting that there may be other stimulation chemicals present as well (Table 2.5-2). Some of the recovered fluids contained high concentrations of TDS, some trace elements (arsenic, selenium and barium), NORM, and hydrocarbons (Table 2.5-2). TDS levels were as high as 260,000 mg L^{-1}. Observed concentrations of the measured parameters were highly variable across wells, even though samples were limited to one operator and two fields. These results confirm that the recovered fluids represent multiple wastewater sources, including formation water and returned stimulation fluids, as was described by the operator (Aera Energy, Appendix 2.F).

The new regulations that go into effect July 2015, are more specific about when the samples for recovered fluids should be collected, and will also require an additional sample for produced water. The new regulations state that the operators must report the "composition of water recovered from the well following the well stimulation treatment, sampled after a calculated wellbore volume has been produced back but before three calculated wellbore volumes have been produced back, and then sampled a second time after 30 days of production after the first sample is taken, with both samples taken prior to being placed in a storage tank or being aggregated with fluid from other wells" (DOGGR, 2014d).

Table 2.5-2. Chemical analyses reported for recovered fluids collected from stimulated wells in North and South Belridge. Measured constituents include salts (TDS), trace metals, organics, NORM and guar (total carbohydrate). Constituents below the detection limit are marked as "ND." A limited amount of data is also available for concentrations of chemical constituents in produced water samples collected (before 1980) from conventional wells across California. All numbers are rounded to two significant digits.

Parameter	Recovered Fluids [a]	Conventional Oil and Gas [b]
General		
Total Dissolved Solids @180 C (mg L^{-1})	430 - 260,000	1,000 – 85,000
Conductivity (µmhos cm^{-1})	240 - 77,000	
pH	6.4 - 9.4	2.6 - 12
Temperature (degrees F)	64 - 130	
Bicarbonate Alkalinity as $CaCO_3$ (mg L^{-1})	ND - 2,900	
Bicarbonate (mg L^{-1})		0 – 13,000
Carbonate Alkalinity as $CaCO_3$ (mg L^{-1})	ND - 470	
Hydroxide Alkalinity as $CaCO_3$ (mg L^{-1})	ND - 0	
Total Alkalinity as $CaCO_3$ (mg L^{-1})	69 - 2,900	0 - 2,100
Major Cations		
Calcium (mg L^{-1})	10 - 13,000	0 – 14,000
Magnesium (mg L^{-1})	7.5 - 700	0 - 2,300
Sodium (mg L^{-1})	93 - 130,000	0 – 100,000
Potassium (mg L^{-1})	2.1 - 66,000	0 – 8,000
Aluminium (mg L^{-1})		0 - 250
Major Anions		
Bromide (mg L^{-1})	ND - 150	1 - 200
Chloride (mg L^{-1})	130 - 190,000	0 - 160,000
Fluoride (mg L^{-1})	ND - 3	
Nitrate as NO3 (mg L^{-1})	ND - 26	0 - 18
Sulfate (mg L^{-1})	28 - 1,900	0 - 15,000
Trace Elements		
Hexavlent Chromium (µg L^{-1})	ND - 9.5	
Antimony (µg L^{-1})	ND - 240	
Arsenic (µg L^{-1})	ND - 1,300	
Barium (µg L^{-1})	ND - 13,000	0 - 170
Beryllium (µg L^{-1})	ND - 50	
Boron (mg L^{-1})	0.26 - 110	0 - 600
Cadmium (µg L^{-1})	ND - 83	
Chromium (µg L^{-1})	ND - 160	0 - 200
Cobalt (µg L^{-1})	ND - 130	
Copper (µg L^{-1})	ND - 1,300	0 - 100
Iron (mg L^{-1})		0 - 540

Parameter	Recovered Fluids [a]	Conventional Oil and Gas [b]
Lead (µg L^{-1})	ND - 88	
Lithum (mg L^{-1})	ND - 41	
Manganese (mg L^{-1})		0 - 50
Mercury (µg L^{-1})	ND - 0.3	
Molybdenum (µg L^{-1})	ND - 500	
Nickel (µg L^{-1})	ND - 260	0 - 30
Selenium (µg L^{-1})	ND - 510	
Silver (µg L^{-1})	ND - 42	
Strontium (mg L^{-1})	0.25 - 230	0 - 600
Thallium (µg L^{-1})	ND - 0	
Vanadium (µg L^{-1})	ND - 220	
Zinc (µg L^{-1})	ND - 1,600	
Radioactivity/NORM		
Recoverable Uranium (pCi L^{-1})	ND - 95	
Gross Alpha (pCi L^{-1})	ND - 220	
Radium 226 (pCi L^{-1})	0.230 - 86	
Radium 228 (pCi L^{-1})	0-52	
Organics (VOCs)		
Benzene (µg L^{-1})	ND - 1,300	
Ethylbenzene (µg L^{-1})	ND - 470	
Toluene (µg L^{-1})	ND - 3,400	
Total Xylenes (µg L^{-1})	ND - 3,600	
p&m Xylenes (µg L^{-1})	ND - 2,500	
o-Xylene (µg L^{-1})	ND - 1,100	
Organics (PAHs)		
Acenaphthene (µg L^{-1})	ND - 86	
Acenaphthylene (µg L^{-1})	ND - 9.8	
Anthracene (µg L^{-1})	ND - 6.5	
Benzo[a]anthracene (µg L^{-1})	ND - 9.8	
Benzo[b]fluoranthene (µg L^{-1})	ND - 3.3	
Benzo[k]fluoranthene (µg L^{-1})	ND - 4.9	
Benzo[a]pyrene (µg L^{-1})	ND - 15	
Benzo[g,h,i]perylene (µg L^{-1})	ND - 0.56	
Chrysene (µg L^{-1})	ND - 20	
Dibenzo[a,h]anthracene (µg L^{-1})	ND - 0	
Fluoranthene (µg L^{-1})	ND - 4.1	
Fluorene (µg L^{-1})	ND - 140	
Indeno[1,2,3-cd]pyrene (µg L^{-1})	ND - 0.85	
Naphthalene (µg L^{-1})	ND - 730	
Phenanthrene (µg L^{-1})	ND - 180	
Pyrene (µg L^{-1})	ND - 6.1	

Parameter	Recovered Fluids [a]	Conventional Oil and Gas [b]
Oil and Gas		
Total Petroleum Hydrocarbons -Crude Oil (µg L^{-1})	ND - 6,700,000	
Methane (mg L^{-1})	ND - 5.4	
Stimulation Fluid Constituents		
Total Carbohydrates (µg L^{-1}) - Guar Indicator	0 - 3,700,000	

[a] *From DOGGR Completion Reports. (N=45, submitted from January 2014 to July 2014).*

[b] *Compiled for this report from the USGS Produced Water Database 2.0 (USGS, 2014b). (N=800).*

3.5.2.3. Management of Recovered Fluids

Recovered fluids are typically stored in tanks at the well site prior to disposal or reuse. According to well completion reports, more than 99% of these fluids are injected into Class II disposal wells. A small amount (0.2%) of recovered fluids are recycled, for example, in future well cleanout operations (Aera Energy, Appendix 2.F).

2.5.3. Produced Water Generated from Stimulated Wells in California

The majority of wastewater from stimulation operations is generated after the well is put into production. Data on produced water volumes and disposition are maintained in DOGGR's production database (DOGGR, 2014c). In California on average, approximately ten barrels of produced water are generated for every barrel of oil extracted (Clark and Veil, 2009). In California, well stimulation typically occurs in oil and gas fields that had long-term conventional production (CCST et al., 2014; Volume I). The produced water streams from stimulated wells are combined with those from conventional wells and treated as one waste stream. Operators are required to submit monthly reports to DOGGR on the volume of oil, gas, and water produced from their wells and the disposition method. These data include produced water disposal, as well as reuse in subsequent oil and gas operations or other beneficial uses.

2.5.3.1. Quantities of Produced Water

We compared the volumes of produced water from stimulated and non-stimulated wells to determine if they were different. Monthly produced water volumes for the first six months of oil production from DOGGR's production database were used for this analysis. The records used from the database were for wells in stimulated and non-stimulated pools in Kern County, which had oil production between January 1, 2011 and September 30, 2013. Only wells with at least 10 months of production data were included. Limiting the data to wells in Kern County focused the analysis on wells located where most well stimulation is occurring. Data on non-stimulated wells in other counties were not included, because

of possible regional differences in wastewater production. Multiple stimulation events at individual wells were excluded from the analysis, in order to prevent bias in the results. In this analysis, volumes of produced waters were evaluated for 1,414 stimulated and 3,247 non-stimulated wells.

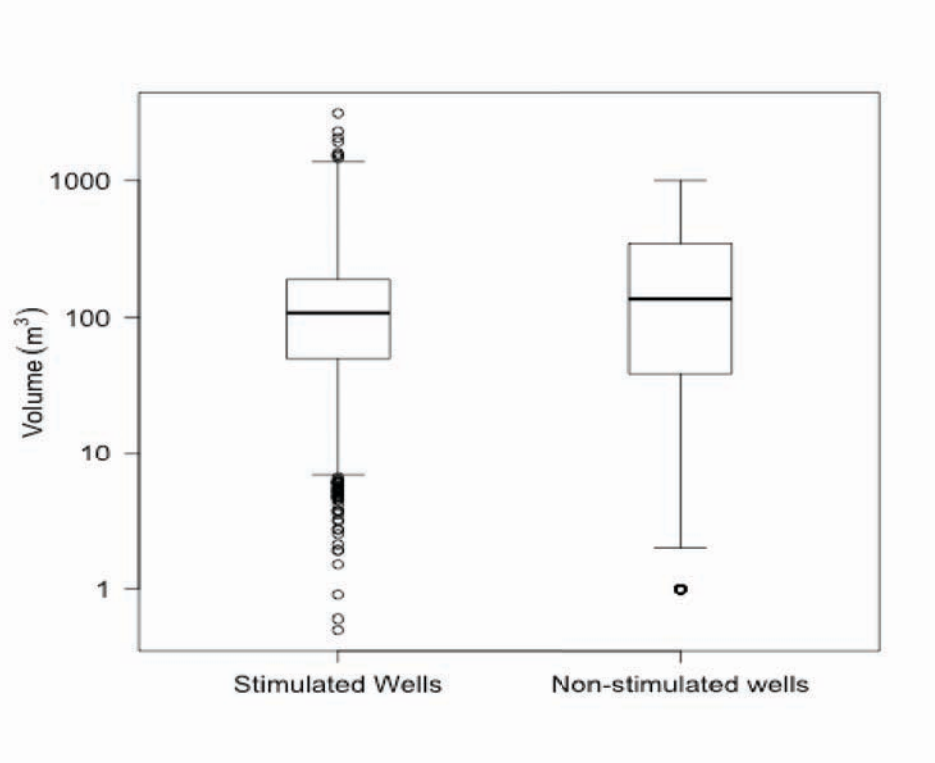


Figure 2.5-4. A comparison of quantities of produced water generated in the first 6 months of oil production from stimulated (N=1,414) and non-stimulated wells (N=3,247) in Kern County. Only wells that had oil production between January 1, 2011 and September 30, 2013 for which there were 10 months of continuous production data were included in the analysis. Note the log-scale in the Y-axis. Boxes show the 25th to 75th percentiles of the data, and the central lines show the median. Whiskers extend to 1.5 times the interquartile range from the box. The circles represent the outliers in the data.

The data do not show substantive differences between the volumes of produced water generated in the first six months from stimulated wells and non-stimulated wells (Figure 2.5-4), even though their distributions were different (Figure 2.5-5).

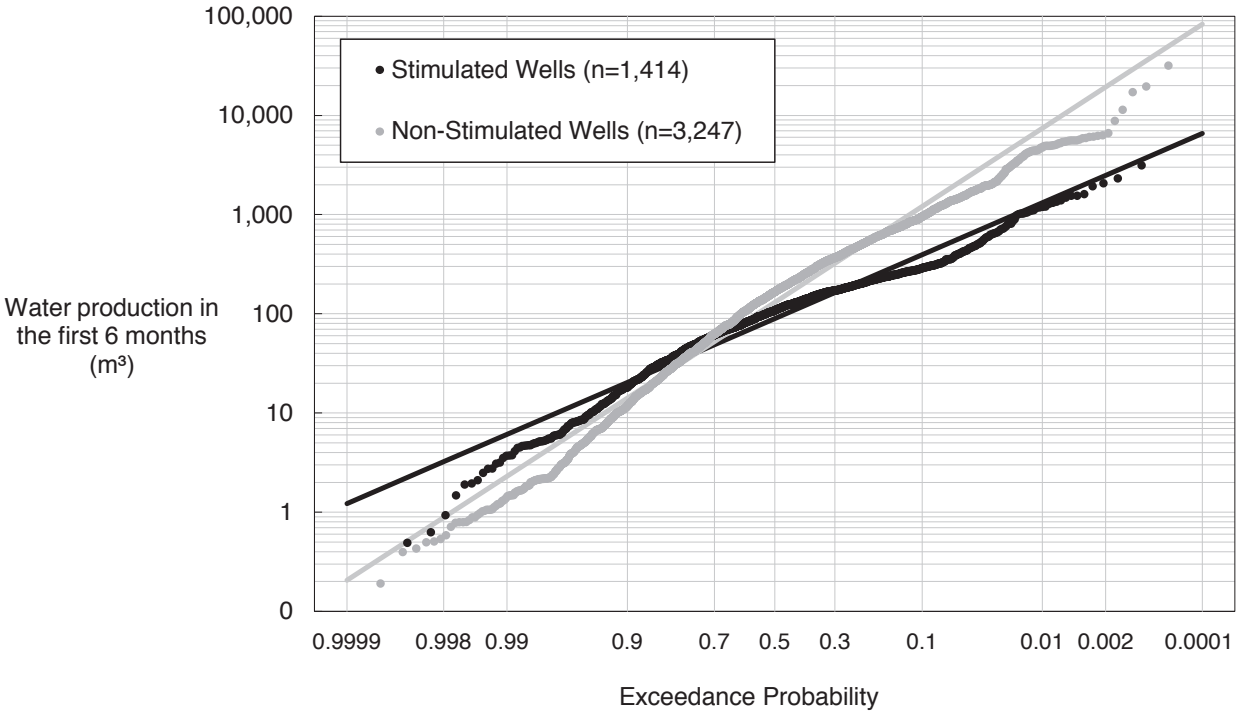


Figure 2.5-5. Probability plot comparing the distributions of produced water volumes for stimulated and non-stimulated wells. The X-axis represents an exceedance probability - i.e., the probability that the produced water generated will exceed a certain value. The Y-axis is on a log scale and has observations of the volumes of produced water in the first 6 months of production, in m^3, for oil and gas wells in Kern County, California with at least 10 months of production data from January 1, 2011 to September 30, 2013. For example, there is a 90% probability that the volume of produced water will exceed 10 m^3 (~60 barrels) for stimulated wells vs. 15 m^3 (~95 barrels) for non-stimulated wells, and a 10% probability that the volume of produced water will exceed ~ 300 m^3 (~1,900 barrels) for stimulated wells vs. ~900 m^3 (5,700 barrels) for non-stimulated wells. These data show that both of the distributions are different, and that there may be a few cases where the non-stimulated wells produce more water than stimulated wells and vice-versa.

2.5.3.2. Chemical Constituents of Produced Water

There are no published studies that have characterized the chemical constituents of produced water from stimulated wells in California. Operators are not required to report the composition of produced water from stimulated wells. New regulations that take effect July, 2015, will require collection of one produced water sample initially and then another "after 30 days of production after the first sample is taken." This is an inadequate sampling regime to characterize how, or if, well-stimulation-fluid additives or their reaction products are returning with produced water.

Since data on produced water specifically from stimulated wells were not available at the time of writing this report, we identified potential constituents that could be present in produced water from stimulated wells based on (1) studies that have analyzed the compositions of produced water from conventional oil and gas wells in California (e.g., Benko and Drewes, 2008), and (2) a few published studies that have characterized produced water from stimulated wells in other regions (CCST et al., 2014 and references therein). Some historical data on produced water composition in California are available in the USGS produced water database (USGS, 2014b), but data for several constituents are not available (Table 2.5-2). Additionally, the produced water can contain returned stimulation fluids, as discussed above.

Produced water from conventional wells primarily consists of water from the targeted formation. Formation water can contain naturally occurring dissolved constituents, such as salts (measured as total dissolved solids or TDS), trace elements, organic compounds, and naturally occurring radioactive materials (NORM). The most concentrated constituents measured in produced water from both conventional and unconventional wells are typically salts, i.e., sodium and chloride (Barbot et al., 2013; Blauch et al., 2009; CCST et al., 2014; Haluszczak et al., 2013; Warner et al., 2012a; 2012b). Magnesium and calcium can also be present at high levels and can contribute to increased water hardness. The TDS concentrations of produced water from conventional wells in California are typically around 10,000–30,000 mg L^{-1} (CCST et al., 2014), although concentrations can be as high as 85,000 mg L^{-1} (Table 2.5-2).

Formation brines can contain high concentrations of trace elements, such as boron, barium, strontium, and heavy metals, which may be brought up to the surface in the produced water (Table 2.5-2). For example, several studies report measuring high levels of trace elements such as barium, strontium, iron, arsenic, and selenium in the waters recovered from fracturing operations in the Marcellus Shale (e.g., Balaba and Smart, 2012; Barbot et al., 2013; Haluszczak et al., 2013; Hayes et al., 2009). Produced waters from oil and gas operations, including those in California, also contain many organic substances, e.g., organic acids, polycyclic aromatic hydrocarbons (PAHs), phenols, benzene, toluene, ethylbenzene, xylenes, and naphthalene (e.g., Fisher and Boles, 1990; Higashi and Jones, 1997; Veil et al., 2004).

Wastewaters from some shale formations have been found to contain high levels of NORM that were several hundred times U.S. drinking water standards (Barbot et al., 2013; Haluszczak et al., 2013; NYSDEC, 2009; Rowan et al., 2011). In 1996, a study of NORM in produced waters in California conducted by DOGGR (DOGGR, 1996) measured bulk radioactivity and some NORM elements (K-40, U-238, U-235, Ra-226, Ra-228 and Cs-137) in both solid and liquid samples. The study found several produced water samples containing elevated levels of radium greater than 25 pCi g^{-1}, but DOGGR did not consider radium to constitute a public health hazard at the time because “produced waters are not used as a source of drinking water.” However, there are several mechanisms by which

produced water can be released into surface and groundwater resources (Section 2.6), and hence elevated levels of potentially contaminating constituents, including NORM, that occur in produced water should be included in future assessments.

More study is needed on produced water in California, particularly characterization of produced water from stimulated wells. Historical (pre-1980) data available on the composition of produced water from conventional wells in California may not be relevant to stimulated wells. The fraction of injected chemicals that return to the surface, and the time period over which they return, are unknown. In addition, the fundamental biogeochemical processes affecting stimulation fluids under reservoir temperature and pressure conditions in the presence of formation minerals have not been investigated. However, it is known that chemical additives are degraded, transformed, sorbed, and otherwise modified in the subsurface, since both specific and non-specific reactions, including strong acid and oxidation reactions, are part of the stimulation process (King, 2012). Other processes, such as biological degradation or transformation of stimulation chemicals, as well as mobilization of formation constituents, can also occur and influence the composition of produced water (Piceno et al., 2014). More data on produced water composition from stimulated and conventional wells in California are needed to assess whether stimulation could affect the produced water chemistry.

2.5.3.3. Management of Produced Water

2.5.3.3.1. Produced Water from Onshore Oil and Gas Operations

As described above, produced water from stimulated wells may contain well-stimulation-chemical additives. Monthly data (1977 to the present) on disposal of produced water are available in DOGGR's Monthly Production database. An analysis was conducted on 2,018 documented well stimulation events which took place between 2011 and 2014 (Volume I, Appendix O) and it was found that data on produced water disposition were available from DOGGR's Monthly Production database for 1,657 wells. For each well for which data was available, we examined disposition during (1) the first full month after stimulation occurred, and (2) from the date of initial well stimulation through June 2014. These results are presented in Table 2.5-3 and Figure 2.5-6.

Table 2.5-3. Produced water disposition during the first full month after stimulation and post stimulation to the present, January 1, 2011-June 30, 2014. Data from the DOGGR Monthly Production database.

	Number of Wells		Total Volume (First Full Month After Stimulation)			Total Volume (Stimulation to June 2014)		
			(m^3)	(acre-feet)	%	(m^3)	(acre-feet)	%
Evaporation–percolation	890	54%	720,000	580	57%	11,000,000	9,200	58%
Subsurface injection	470	28%	330,000	260	26%	4,100,000	3,300	21%
Other	130	8%	180,000	140	14%	3,400,000	2,700	17%
Not reported	150	9%	31,000	25	3%	510,000	410	3%
Surface body of water	2	0.1%	2,100	1.7	0.2%	95,000	77	0%
Unknown	14	1%	-	-	-	-	-	-
Sewer system	-	-	-	-	-	-	-	-
Evaporation - lined pits	-	-	-	-	-	-	-	-
Total	**1,700**	**100%**	**1,300,000**	**1,000**	**100%**	**19,000,000**	**15,769**	**100%**

Note: All numbers rounded to two significant figures. Numbers may not add up due to rounding. Subsurface injection includes injection into Class II disposal wells as well as injection for enhanced oil recovery, i.e., water flooding and steam flooding.

Data Source: DOGGR Monthly Production database

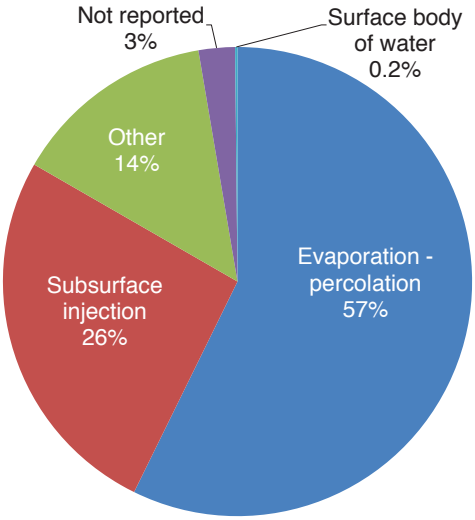


Figure 2.5-6. Produced water disposition during the first full month after stimulation. Data for stimulated wells throughout California were evaluated for the time period 2011-2014. Data from the DOGGR Monthly Production database.

Note: Subsurface injection includes injection into Class II disposal wells as well as injection for enhanced oil recovery, i.e., water flooding and steam flooding.

Between January 2011 and June 2014, these 1,657 stimulated wells generated a total of 1.3 million m^3 (1,000 acre-feet) of produced water during the first full month following stimulation. Evaporation-percolation in unlined surface impoundments (also referred to as percolation pits, ponds, or sumps) was reported to be the most common disposition method for these stimulated wells. According to California records, nearly 60% of the produced water from stimulated wells, or 720,000 m^3 (580 acre-feet), was disposed to unlined pits for evaporation and percolation during the first full month after stimulation. While produced water disposal in percolation pits has been reported in several California counties (e.g., Fresno, Monterey, and Tulare counties), disposal of produced water from stimulated wells in percolation pits was limited to Kern County and was associated with wells in Elk Hills (65%), South Belridge (27%), North Belridge (5.5%), Lost Hills (2.5%), and Buena Vista (<1%) (Table 2.5-4). Overall, use of percolation pits is common in production areas where well stimulation is applied and an estimated 40% of all produced water from stimulated oil pools is discharged to percolation pits for disposal. There were no reports of discharge to lined surface impoundments for evaporation only as a disposal method.

It is of note that operators have suggested that the information supplied to DOGGR specifying disposal practices for produced water may not be accurate. Chevron, for example, says that it ceased disposing produced water from its Lost Hills operation in unlined pits in 2008 (Appendix 2.E), although DOGGR records indicate this practice was continuing in 2014. Likewise, Occidental Petroleum (now California Energy Resources) says it has used subsurface injection for all produced water in Elk Hills (Nelson, 2014, personal communication). Our analysis is reliant on official data reported to DOGGR, which shows that these and other operators sent the majority of their produced water to unlined pits for evaporation and percolation, but the reports from industry suggest that more produced water may be disposed of in injection wells and less to percolation pits now, than in the past. Further investigation is needed to substantiate current wastewater management practices—particularly in relation to produced water from stimulated wells that may contain hydraulic fracturing fluids—and determine legacy effects from past disposal practices.

Table 2.5-4. Produced water disposition by evaporation-percolation during the first full month after stimulation by field, January 1, 2011 – June 20, 2104. Data from the DOGGR Monthly Production database.

Field	Water volume (m^3)	Water volume (acre-feet)	Percent
Elk Hills	460,000	380	65%
South Belridge	190,000	160	27%
North Belridge	39,000	32	5.5%
Lost Hills	18,000	14	2.5%
Buena Vista	2,000	2	0.27%
Total	**720,000**	**580**	**100%**

Note: All figures rounded to two significant figures. Numbers may not add up due to rounding.

Subsurface injection into Class II wells is the second most commonly reported disposition method for stimulated wells in California. Class II wells include saltwater disposal wells, enhanced recovery wells, and hydrocarbon storage wells (U.S. EPA, 2014). With enhanced oil recovery, reinjection of produced water serves multiple purposes, including enhancing product recovery, preventing subsidence, and disposing of produced water generated during production. About one-quarter of the produced water from stimulated wells, or about 330,000 m^3 (260 acre-feet), was injected into Class II wells for disposal or enhanced recovery (Table 2.5-3, Figure 2.5-6). While much of this occurred in Kern County, subsurface injection was the only disposition method reported in several counties, including Colusa, Fresno, Glenn, Ventura, and Orange County (Table 2.5-5).

Table 2.5-5. Produced water disposition by subsurface injection during the first full month after stimulation, by county, January 1, 2011 – June 30, 2014. Data from the DOGGR Monthly Production database.

County	Water volume (m^3)	Water volume (acre-feet)	Percent
Colusa	47	0.04	0.014%
Fresno	1,900	2	0.59%
Glenn	7.6	0.01	0.0023%
Kern	270,000	216	82%
Los Angeles Offshore	52,000	42	16%
Orange	1,700	1	0.52%
Sutter	430	0	0.13%
Ventura	3,500	3	1.1%
Total	**330,000**	**260**	**100%**

Note: All figures rounded to two significant figures. Numbers may not add up due to rounding.

As shown in Table 2.5-3, very few operators discharge produced water from stimulated wells into creeks or streams, with only two wells reported to be discharging a total of 2,100 m^3 (1.7 acre-feet) of produced water into surface water bodies during the first full month following stimulation. There were no reports of produced water from stimulated wells being disposed of in sewer systems.

The disposition method for 17% of the produced water from stimulated wells is either not known or not reported. “Other” was the third most common disposition method reported by operators—accounting for 14% of the produced water from stimulated wells. Similarly, the disposition method for 3% of the produced water was not reported. DOGGR staff confirmed that some operators are using the “other” category to describe disposition that is, in fact, included in some of the other categories, e.g., subsurface injection, surface body of water, sewer disposal, etc. (Fields, 2014). Some disposition methods, however, are not explicitly covered in these categories, such as reuse for irrigation, well stimulation,

or other beneficial purposes, although there is anecdotal evidence that reuse for these purposes is occurring in California (for more information, see Section 2.6). These results suggest a need to improve data collection and better understand wastewater management practices in California.

2.5.3.3.2. Produced water from Offshore Oil and Gas Operations

California has four offshore oil platforms (Esther, Eva, Emmy, and Holly) and several man-made islands (Long Beach Unit, Rincon Island) operating in state waters. Well stimulation operations have been reported on Platforms Esther, Eva, and on the Long Beach Unit (THUMS Islands). There are also 23 oil platforms operating in federal waters off the coast of California, of which well stimulation operations have been reported on Platforms Gail, Gilda, and Hidalgo. Well stimulation accounts for a small fraction of offshore oil and gas production. It is estimated that approximately 12 hydraulic fracturing operations occur per year in state waters, and less than 10% of wells are hydraulically fractured in federal waters (Volume I, Chapter 3).

Options for the management and treatment of produced water on offshore oil platforms and islands are limited by treatment technology footprint, transportation costs, storage capacity, effluent limitations, and disposal options. Operations in state waters typically treat produced water to meet requirements for re-injection for enhanced oil recovery, and operations in federal waters treat produced water for discharge. Permitted disposal options vary as platforms located in federal waters are regulated under a general NPDES permit issued by U.S. Environmental Protection Agency (U.S. EPA), Region 9 (U.S. EPA, 2013a), while operations in California state waters are regulated under individual NPDES permits issued by regional water quality control boards.

On Platforms Esther and Eva, oil, gas, and produced water are separated using three-phase separators. The produced water then goes through a series of treatment processes to remove residual oil and suspended solids (California State Lands Commission, 2010a; 2010b).[2] Once treated, produced water is typically re-injected into the producing formation for enhanced oil recovery. On the Long Beach Unit, a portion of the produced water is reused as base fluid for well stimulation (Garner, 2014, personal communication).

Platforms operating in federal waters off the coast of California are permitted to discharge produced water that has been treated, as stipulated under a general NPDES permit.[3] When well stimulation fluids co-mingle with produced water, the mixture is managed, treated, and discharged according to produced water stipulations. Each of the 23 platforms has a maximum annual allowable produced water discharge volume, which ranges from

2. There is no evidence of a separate treatment system for managing wastewaters from well stimulation operations on Platform Esther. It is expected that wastewaters from well stimulation operations on Platforms Esther and Eva are subject to the same treatment processes and fate as produced water.

3. NPDES permit No. CAG280000

0.25 million to 8.9 million m^3 (206 to 7,192 acre-feet) per platform (U.S. EPA, 2013a). Platforms Gail and Hidalgo are allowed to discharge 0.7 million m^3 (560 acre-feet) and 2.9 million m^3 (2,350 acre-feet), respectively. Platform Gilda's discharge allowance is combined with that for Platform Gina at 4 million m^3 (3,300 acre-feet).

For a permitted discharge, oil and grease levels are measured weekly and must be lower than 29 mg L^{-1} monthly average and 42 mg L^{-1} daily maximum in discharged wastewater, according to effluent limitations in Subpart A of 40 CFR Part 435 in the Clean Water Act. The permit does not allow discharge of free oil, where free oil is defined as oil which will cause a film, sheen, or discoloration to the water surface upon discharge (U.S. EPA, 2014). Fourteen platforms, including Platforms Gail, Gilda, and Hidalgo, have specific monitoring and effluent requirements for produced water discharge, with measurements typically occurring on an annual or monthly basis. Platforms Gail, Gilda, and Hidalgo must also monitor for various aromatic hydrocarbons, but only have effluent limits for undissociated sulfide. All other platforms must monitor 26 constituents of concern.[4] These data are submitted to the EPA. The number of constituents sampled is based on previous studies where constituents present at concentrations above or near the water quality standards were identified and listed in the permits (U.S. EPA, 2013b). Sampling frequency depends on the frequency of discharge; however, constituents must be sampled "at least once during the last two years" of the permit (U.S. EPA, 2013a). Discharges are not monitored for constituents specific to or indicative of hydraulic fracturing, and the timing of sampling is unlikely to coincide with or measure any potential impacts from well stimulation treatments.

2.6. Contaminant Release Mechanisms, Transport Pathways, and Driving Forces

2.6.1. Overview of Contaminant Release Pathways

Well stimulation and associated activities can result in the release of contaminants into the environment, including into surface water and groundwater resources. Releases can occur during chemical transport, storage, mixing, well stimulation, well operation and production, and wastewater storage, treatment, and disposal. The term "release mechanism" refers to the way in which a contaminant migrates from its intended containment (natural or manmade) into the surrounding environment. Once released, contaminants can be transported through various mechanisms (e.g., percolation into soil, transport into groundwater, runoff to local streams) or transformed through physical, chemical, and biological processes. A *physical connection*, either natural or induced, between the release location and the impacted surface or groundwater body is referred to as a "transport pathway." A *driving force* (e.g., differences in hydraulic head or pressure) is required for contaminant migration into the connected surface or groundwater body.

4. Where the California Ocean Plan also contains criteria for a select constituent, then the more stringent of the two is used, as the California Ocean Plan can regulate "discharge outside the territorial waters of the State [that] could affect the quality of the waters of the State" (SWRCB, 2012).

The extent to which water resources are affected by releases of well stimulation chemicals or wastewaters depends on the amount and type of contaminant(s) released, existence of transport pathways and corresponding driving forces, and the transformations occurring during transport. Other factors that impact the probability of contaminant migration include reservoir depth, physical and hydrological properties of the formation, production strategies, drilling and casing practices, and the unique geologies of each oil and gas-producing region.

Release mechanisms and transport pathways can occur at the surface or in the subsurface, and are associated with a variety of activities during the production process (e.g., well stimulation, wastewater management and disposal, and well operation). Surface releases are typically easier to identify and associate with a particular activity. Subsurface releases are generally more difficult to detect, associate with a particular release mechanism, and mitigate. Reservoir and stimulation fluids can migrate through the subsurface if (1) surface releases eventually percolate into groundwater; (2) produced water is directly injected into protected groundwater; or (3) if transport pathways out of the reservoir being fractured (out-of-zone) have been created through stimulation operations, either through direct fracturing into overlying aquifers or via out-of-zone connection to a preexisting pathway (e.g., a preexisting fracture network, a fault, or some other permeable feature). While transport through preexisting or induced subsurface pathways has been documented in conventional oil and gas operations, it is not known whether stimulation increases the frequency of occurrence of such pathways. Regardless of the uncertainty whether stimulation increases the frequency of leakage pathways, stimulation introduces a new set of water quality concerns for leakage, through pathways documented from conventional oil and gas operations, due to the use of stimulation chemicals and the commingling of produced water and returned stimulation fluids.

2.6.2. Potential Release Mechanisms to Water in California

In this section, we identify potential release mechanisms specific to well stimulation activities that can (1) form transport pathways (natural, induced, or a combination) to water resources and (2) allow stimulation or reservoir fluids to migrate into water resources if the appropriate driving forces are present. We examined several plausible release mechanisms for surface and groundwater contamination associated with onshore well stimulation, based on an exhaustive literature review of release events and hazards that have been reported in the U.S. (Table 2.6-1). While release mechanisms and transport pathways that occur during post-stimulation and wastewater management apply to all oil and gas development in California, they are relevant to stimulated wells because produced water from stimulated wells may contain hazardous chemicals from well stimulation fluids.

Table 2.6-1. Activities and associated release mechanisms for the different stages of well stimulation

Activities	Release Mechanisms and Transport Pathways	Releases
Preparation: Site development, well drilling, construction and completion	• Erosion and surface runoff* • Well blowout resulting from failure to control well pressure and improper well installation* • Release of drilling fluids and waste during handling, storage and disposal* • Migration through existing or induced pathways or other subsurface features (such as faults, fractures, or permeable adjacent formations)*	• Soil/particulate matter in stormwater runoff • Drilling fluids and wastes • Oil and gas • Formation water
Well stimulation	• Transportation accident • Equipment failure • Leakage from onsite chemical storage • Spills during chemical mixing • Pipe failure (both above and below ground) • Well failure due to stimulation • Problems related to drilling, completion, or well design errors (e.g., poor cementing, wrong perforation depth) • Migration via other pathways intercepted by fractures (including plugged, deteriorated, or abandoned wells) • Fractures or other permeable pathways directly intercepting groundwater resources	• Additives • Stimulation fluids • Oil and gas • Formation water
Post-stimulation: Well cleanout and production	• Pipe failure (both above and below ground) • Well failure due to drilling, completion or well design errors (e.g., leakage through compromised casing and cement) • Migration via other pathways intercepted by fractures (including plugged, deteriorated, or abandoned wells, faults, fractures, permeable adjacent formations)	• Well cleanout fluids • Wastewaters • Oil and gas • Formation water
Wastewater management: Handling, storage, reuse, and disposal	• Spills and leaks during storage and handling • Transportation accident • Pipe failure (both above and below ground) • Overflow from storage reservoir • Percolation (from storage or disposal pits) • Reuse of produced water for beneficial purposes (e.g., irrigation) • Disposal of produced water into sewer system (and subsequent disposal of treatment residuals) • Improper siting of disposal wells (into aquifer or protected groundwater) • Failure of disposal well (e.g., leakage through casing or cement) • Migration through existing pathways during subsurface disposal (e.g., faults, fractures, permeable overburden) • Illegal discharge	• Wastewaters • Oil and gas • Treatment residuals (including disinfection byproducts)

*Note: * Release mechanisms that are not within the scope of this assessment since they are part of routine oil and gas development and there are no unique impacts associated with well stimulation. While release mechanisms and transport pathways that occur during post-stimulation and wastewater management apply to all oil and gas development in California, they are of particular relevance for stimulated wells (and are included in this study) because (1) produced water from stimulated wells may contain returned stimulation fluids, and (2) the quality of formation water from stimulated reservoirs may differ from that of conventional reservoirs.*

We narrowed the broad set of possible release mechanisms to a subset that is most relevant for California (Figures 2.6-1 and 2.6-2, Table 2.6-2). In the following sections, we list several incidents of contamination that have occurred in California or other oil and gas producing regions, to show that these release mechanisms are viable, and relevant for California.

The California-specific release mechanisms are classified as normal, accidental, and intentional (Table 2.6-2). "Normal" release mechanisms result from practices that are part of routine operations in the California oil and gas industry, and include disposal of produced water in unlined pits, injection of produced water into potentially protected groundwater, reuse of produced water for irrigation, and disposal of produced water in sewer systems. "Accidental" release mechanisms can be of several types, including errors in design and execution of the stimulation operation—such as out-of-zone fracturing, leakage through degraded or impaired wells, leakage through natural subsurface features, surface spills and leaks, or consequences of natural disasters such as earthquakes and floods. It should be noted that in California, where fracturing depths are much shallower than in other parts of the country, fractures induced by hydraulic fracturing could potentially form direct transport pathways to groundwater. Nationally, several incidents have been caused by leakage through degraded abandoned wells and leakage of stray gas from production or other wells into groundwater. Surface releases caused by spills or leaks have been conclusively linked to stimulation operations. "Intentional" release mechanisms are unauthorized or unpermitted releases such as illegal discharges.

Finally, we assigned a priority for each release mechanism based on the release type (e.g., all releases that are part of normal operations are considered high priority), and direct or indirect evidence indicating their likelihood of occurrence in California (Table 2.6-2). We focus on release mechanisms and transport pathways from hydraulic fracturing operations, and assume that this covers concerns associated with matrix acidizing operations, given that the latter follow a similar process as hydraulic fracturing operations, albeit using less equipment, lower injection pressures, and no proppant (Volume I, Chapter 2).

Table 2.6-2. Assessment of release mechanisms associated with stimulation operations for their potential to impact surface and groundwater quality in California. Considerations for the priority ranking include whether the releases occur due to activities that are part of normal operations, and the likelihood of the occurrence in California. References for this table are provided in the text.

Release Mechanism	Release type*	Has occurred in California?	Has occurred in other places?	Evidence associating release to hydraulic fracturing?	Priority
Percolation of produced water from unlined pits	Normal	Yes	Yes	Yes	High
Injection of recovered fluids and produced water into potentially protected groundwater via Class II wells	Normal	Yes	No	Unknown	High
Reuse of produced water for irrigation	Normal	Yes	No	Unknown but likely	High
Disposal of produced water in sewer systems	Normal	Yes	Yes	Unknown in California, yes in other states	High
Leakage through hydraulically induced fractures	Accidental	Unknown	Unknown	Unknown	Medium
Leakage through failed inactive wells (abandoned, buried, idle or orphaned)	Accidental	Unknown	Yes	Unknown	Medium
Leakage through active wells (production, disposal or other wells)	Accidental	Unknown	Yes	Yes	Medium
Leakage through other subsurface pathways (preexisting natural fractures, faults, or other permeable features)	Accidental	Yes	Unknown	Unknown	Medium
Surface and near-surface spills and leaks	Accidental	Yes	Yes	Unknown	Medium
Operator error	Accidental	Unknown	Yes	None in California, yes elsewhere	Low
Illegal discharges of wastewater from oil and gas operations	Intentional	Yes	Yes	Yes	Low

**The type of activity leading to the release. Categories are*

Normal: Activity is part of normal operations, and release occurs by design.

Accidental: Release was caused due to an accident, but can be prevented by following proper design and protocols

Intentional: Release was intentional despite being unauthorized, and can be prevented by proper oversight and monitoring.

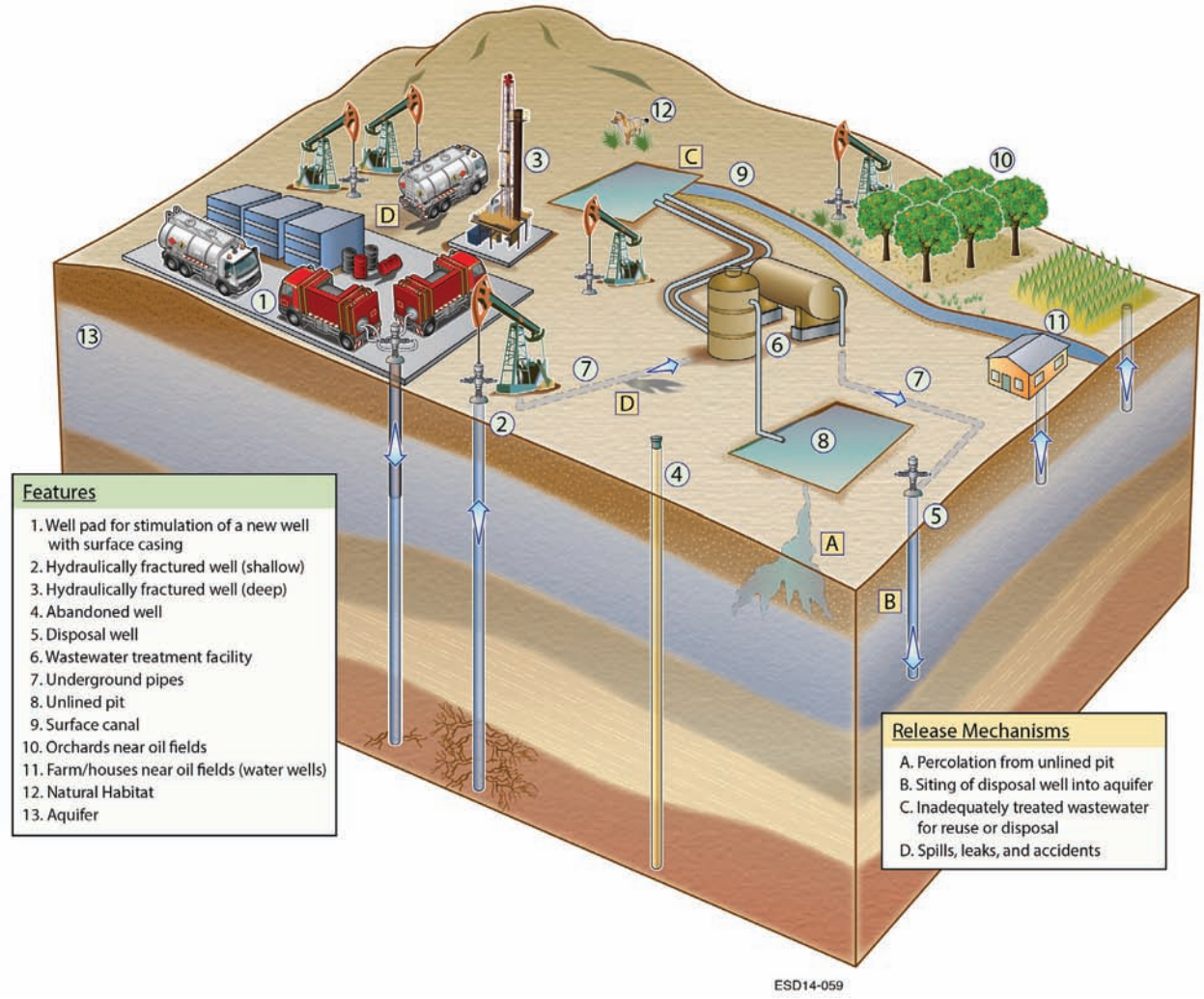


Figure 2.6-1. Potential contaminant release mechanisms that originate at the surface related to stimulation, production, and wastewater management and disposal activities in California. The diagram is not drawn to scale.

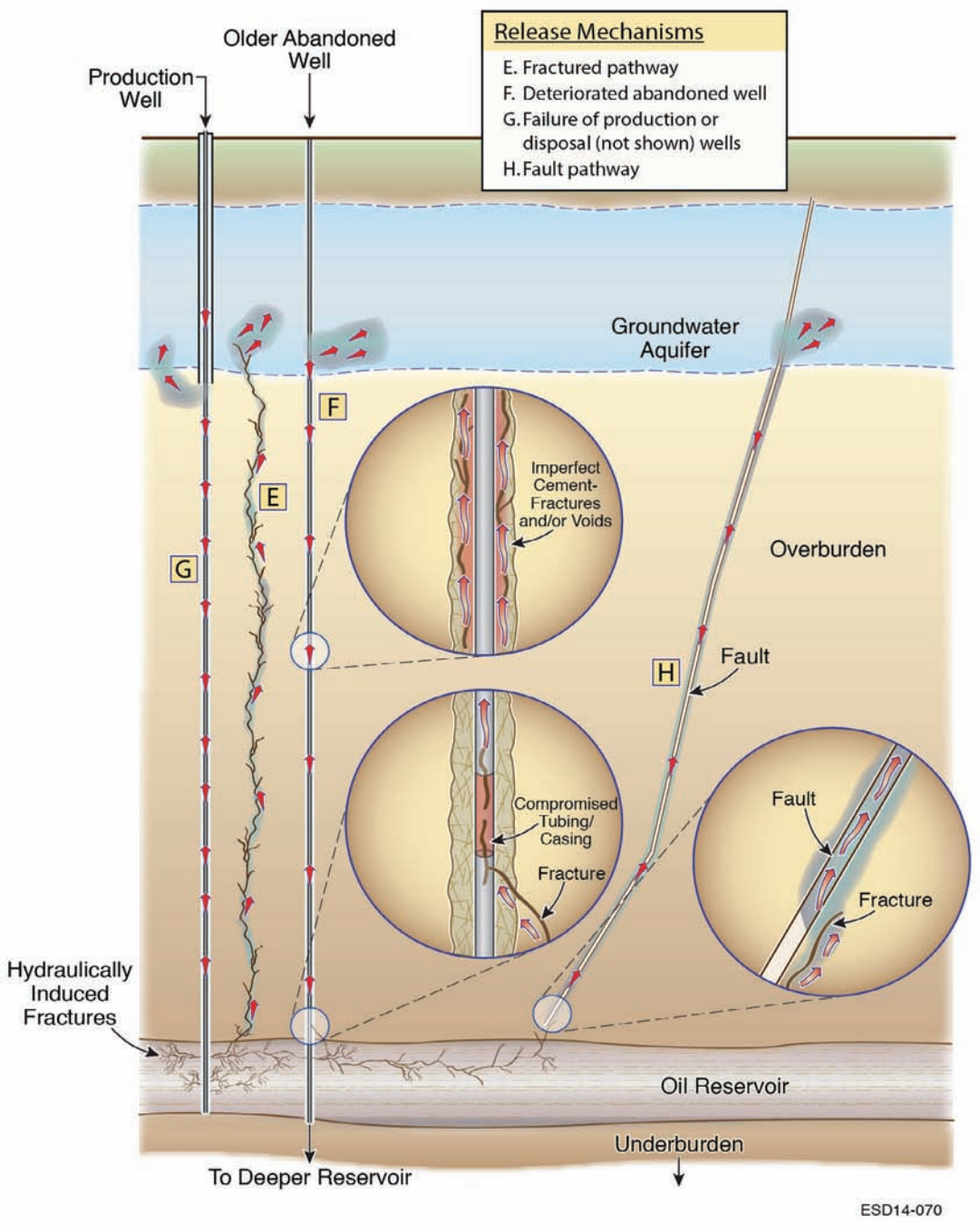


Figure 2.6-2. Potential release mechanisms and transport pathways in California that could originate in the subsurface. These include leakage through failed (production, abandoned or disposal) wells, migration through intercepted fractures and fault activation. The diagram is not drawn to scale.

2.6.2.1. Use of Unlined Pits for Produced Water Disposal

As described above, evaporation-percolation in unlined surface impoundments (percolation pits) is a common disposition method for produced water from stimulated wells in California (Section 2.5). Because the primary intent of unlined pits is to percolate water into the ground, this practice provides a direct pathway for the transport of produced water constituents, including returned stimulation fluids, into groundwater. Some states, including Kentucky, Texas, and Ohio, have phased out the use of unlined pits for disposal (Kell, 2011; 401 KAR 5:090 Section 9(5)(b)(1)).

The state's nine Regional Water Quality Control Boards have primary authority to regulate disposal pits in California.[5] Most of the instances of discharge into percolation pits occurred in the region under the authority of the Central Valley Regional Water Quality Control Board. Within that region, disposal of produced water in percolation pits overlying groundwater with existing and future beneficial uses has been allowed if the wastewater meets certain salinity, chloride, and boron thresholds.[6] Produced water that exceeds the salinity thresholds may also be discharged in "unlined sumps, stream channels, or surface water if the discharger successfully demonstrates to the Regional Water Board in a public hearing that the proposed discharge will not substantially affect water quality nor cause a violation of water quality objectives" (CVRWQCB, 2004). There was previously no testing required, nor thresholds specified, for other contaminants, including chemicals used for well stimulation or other routine oilfield activities. The Central Valley Regional Water Quality Control Board implemented an order on April 1, 2015 requiring operators to conduct a chemical analysis of wastewater disposed in active produced water disposal ponds in the Central Valley; however, the list of constituents to be analyzed does not include any indicators for stimulation fluid constituents (CVWQCB, 2015).

Figure 2.6-3 shows active and inactive unlined pits and ponds in the Central Valley and along the Central Coast. Presumably, the pits are largely used to deliberately percolate wastewater for the purpose of disposal. Active pits are primarily found on the east and west side of the southern San Joaquin Valley, although a small number of active pits can also be found in Monterey and Santa Barbara Counties. The Central Valley Regional Board is currently conducting an inventory of unlined pits in the Central Valley. As of April 2015, a total of 933 pits have been identified, of which 62% are active and 38% are inactive. An estimated 36% of the active unlined pits are operating without the necessary permits from the Central Valley Regional Board (Holcomb, 2015). Central Valley Regional Board

5. Local Air Districts also regulate some aspects of oilfield pits, e.g., volatile organic carbon (VOC) emissions.

6. According to the Water Quality Control for the Tulare Basin, which was developed by the Central Valley Regional Water Quality Control Board, tdisposal of oil field wastewater in pits overlying groundwater with existing and future beneficial uses is permitted if the salinity of the wastewater is less than or equal to 1,000 micromhos per centimeter (μmhos cm^{-1}) electrical conductivity (EC), 200 milligrams per liter (mg L^{-1}) chlorides, and 1 mg L^{-1} boron (CVRWQCB 2004).

staff expects to issue 180 enforcement orders for facilities that are not permitted or are operating with outdated permits by the end of 2015. Cease and desist orders have been issued for some facilities operating with outdated permits (Holcomb, 2015). An analysis of groundwater quality near these pits can be found in Section 2.7.

There is not one centralized location for reporting and tracking locations of unlined or disposal pits in California, so any list of disposal pits must be considered approximate. The Central Valley Regional Board, which recently launched an investigation into unlined pits, found that more than one-third of the pits located in their jurisdiction were functioning without the proper permits, indicating that there may be additional pits of which the state is unaware (Holcomb, 2015). The DOGGR production database indicates that produced water is sent to evaporation-percolation disposal ponds in counties where there are no reported pit locations, suggesting that there may be unreported pits in those counties. For example, according to the production database, 47,000 m^3 (38 acre-feet) were sent to evaporation-percolation ponds in Ventura County in 2013 (DOGGR, 2014c), despite there being no reported pit locations within or near the borders of that county (Holcomb, 2015).

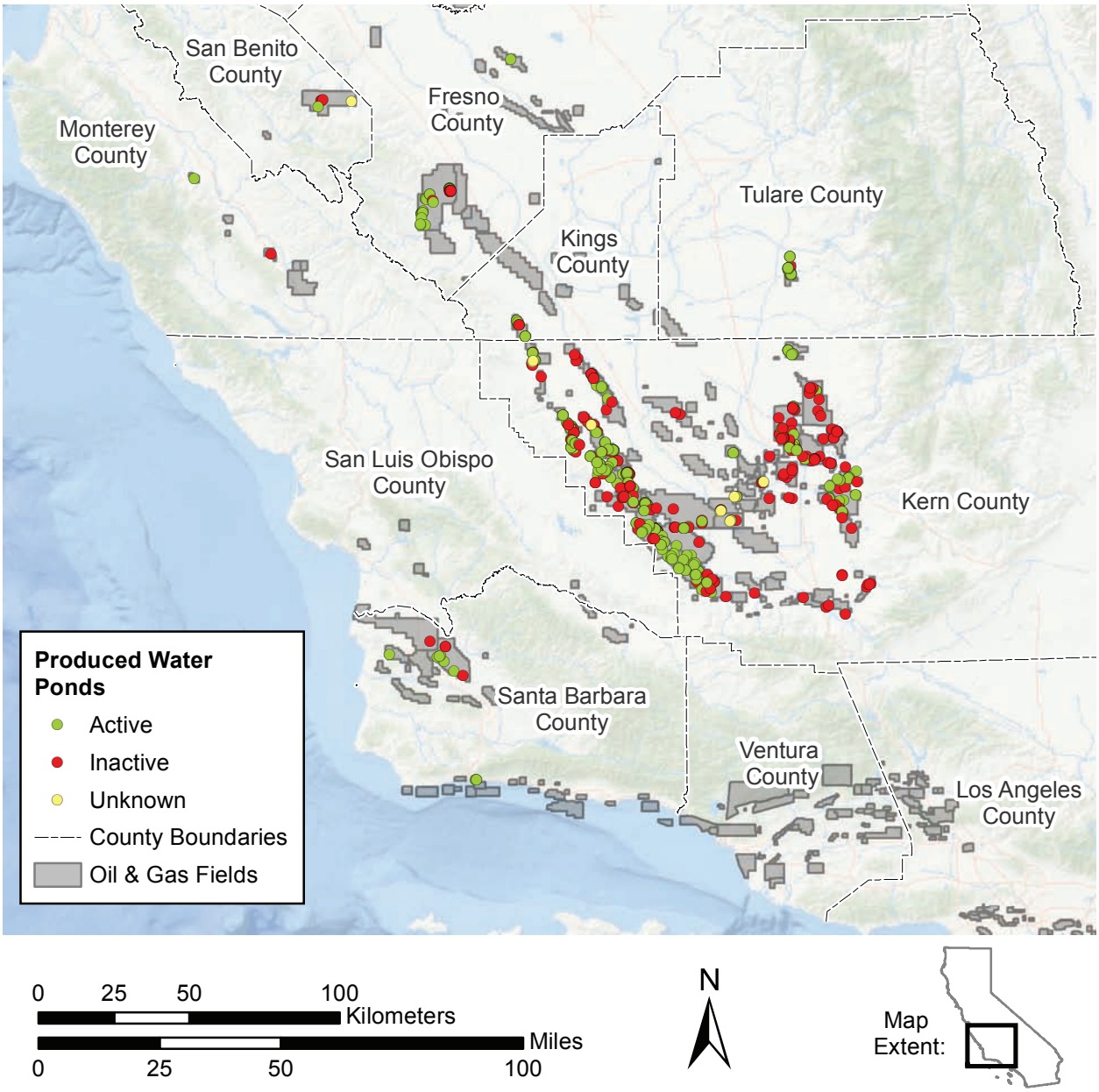


Figure 2.6-3. Unlined pits used for produced water disposal in the Central Valley and the Central Coast, 2015. Data from CVRWQCB 2015; Borkovich 2015a; 2015b (Appendix 2.G).

There is ample evidence of groundwater contamination from percolation pits in California and other states (e.g. CVRWQCB, 2015; Holcomb, 2015; Kell 2011). For example, in California, the Central Valley Regional Water Quality Control Board determined that several percolation pits in Lost Hills and North and South Belridge had impacted groundwater, and ordered their closure (CVRWQCB, 2015). In these cases, monitored natural attenuation rather than active remediation was selected as the method for

corrective action for improving the groundwater quality. Groundwater contamination has also been associated with unlined pits in other states. Kell (2011) reviewed incidents of groundwater contamination caused by oil field activities in Texas between 1993 and 2008 and in Ohio between 1983 and 2007. Of the 211 incidents in Texas over the 16-year study period, 27% were associated with unlined infiltration pits, which have been phased out in Texas starting in 1969 (Kell, 2011). Of the 185 groundwater-contamination incidents in Ohio over a 25-year period, 5% (or 10 incidents) were associated with the failure of unlined pits. Like Texas, unlined disposal pits are no longer used in Ohio, and no incidents have been reported since the mid-1980s (Kell, 2011). While these studies and others linking wastewater percolation and unlined pits to groundwater contamination are not specific to well stimulation fluids, they are illustrative of the implications of this disposal method. Moreover, the presence of stimulation fluids in the produced water is likely to increase the risk of groundwater contamination.

A case in Pavillion, WY, raises additional concerns about the use of unlined pits for produced water disposal. According to the U.S. EPA draft report, released in 2011, high concentrations of hydraulic fracturing chemicals found in shallow monitoring wells near surface pits "indicate that pits represent a source of shallow ground water contamination in the area" (Digiulio et al., 2011). At least 33 unlined pits were used to store or dispose of drilling muds, flowback, and produced water in the area. Neither the company responsible for the natural gas wells, nor the other stakeholders contested these findings (Folger et al., 2012).

2.6.2.2. Injection of Produced Water into Protected Groundwater via Class II Wells

Subsurface injection was the second most common disposal method for produced water from stimulated wells (Section 2.5). Studies show that with proper siting, construction, and maintenance, subsurface injection is less likely to result in groundwater contamination than disposal in unlined surface impoundments (Kell, 2011). However, there are significant concerns about whether California's Class II underground injection control (UIC) program is adequately protective of underground sources of drinking water (USDWs) – defined as groundwater aquifers that are used for water supply or could one day supply water for human consumption.[7]

In 2011, at the request of EPA Region 9, an independent consultant reviewed California's UIC Program and found inconsistencies in how USDWs are defined (Walker, 2011). Specifically, the DOGGR program description refers to the protection of freshwater containing 3,000 mg L^{-1} or less TDS. Current federal regulation, however, defines USDWs as containing less than 10,000 mg L^{-1} TDS. This suggests that USDWs in California containing between 3,000 and 10,000 mg L^{-1} TDS are not adequately protected. More recently, DOGGR acknowledged that it has approved UIC projects in zones with aquifers

7. The UIC program was developed as a result of the 1974 Safe Drinking Water Act and was intended to protect USDWs.

lacking exemptions, even though those zones would likely qualify for an exemption under current regulations.[8] Additionally, new information has indicated that, for several decades, injection activities have been allowed in 11 other aquifers that were thought to be exempt; however, the geologic basis for those exemptions is "now in question" (Bohlen and Bishop, 2015).

In response to these issues, DOGGR is reviewing more than 30,000 of the state's 50,000 Class II wells, and is expected to complete that review in early 2016. Given their mutual role in protecting water resources, DOGGR and the State Water Board are working together on this review. In 2014, DOGGR ordered the immediate closure of 11 disposal wells in Kern County that potentially present health or environmental risks, and State Water Board staff identified 108 water supply wells located within a one-mile radius of these wells.[9] Subsequent sampling found no sign of contamination from oil and gas operations (SWRCB, 2014b). Currently, 140 active wells are under immediate review by the State Water Board, because they are operating in aquifers that lack hydrocarbons and contain water with less than 3,000 mg L^{-1} TDS. These wells are being reviewed for "proximity to water supply wells or any other indication of risk of impact to drinking water and other beneficial uses" (Bohlen and Bishop, 2015). The State Water Board is reviewing 150 injection wells per month and expects to be done with its review in May 2015. Going forward, DOGGR has proposed a schedule and process to the U.S. EPA to bring California's UIC program into compliance with federal regulations. Further analysis on this subject can be found in Volume III, Chapter 5.

2.6.2.3. Reuse of Produced Water for Irrigated Agriculture

Produced water is commonly reused for beneficial purposes, including steam flooding, irrigation, and industrial cooling. In some cases, the produced water is treated prior to reuse, but in others it is simply blended with freshwater to bring the levels of salts and other constituents down to an acceptable range. In California, in in particular the San Joaquin Valley, there is growing interest in expanding the beneficial reuse of produced water for agriculture, particularly for irrigation, due to the co-location of oil, gas, and agricultural operations and ongoing water scarcity concerns in these areas. The use of produced water from unconventional production raises specific or unique concerns, because of the variety of chemicals used during well stimulation that may end up mingled with produced water and the unknowns concerning the toxicity and environmental profile of those chemicals (discussed in the characterization of chemicals section, above).

8. An "exempt aquifer" is an aquifer that meets the criteria for protection but that protection has been waived because it is not currently being used — and will not be used in the future — as a drinking water source, or it is not reasonably expected to supply a public water system due to a high total dissolved solids content.

9. Since review, two of the 11 wastewater disposal wells have been authorized to resume operations.

It is not known if produced water from stimulated wells is or has been used for irrigation in California. According to data from the Central Valley Regional Board, there are currently five fields (Deer Creek, Jasmin, Kern River, Kern Front and Mount Poso) where produced water is reused to irrigate crops. Of these fields, well stimulations have only been reported in Kern River and Mount Poso. In Mount Poso, the last reported hydraulic fracture was in 2003. Although hydraulic fracturing was reported as recently as 2014 in the Kern River, only three hydraulic fracturing operations have been reported since 2012.

Produced water from the Kern River oil field irrigates the Cawelo Water District, a service area covering 182 km^2 (45,000 acres), of which roughly 82% of crops are permanent crops, including citrus, nuts, and grapes (Cawelo Water District, 2014). The water is treated at the Kern Front No. 2 Treatment Plant before it is delivered to the water district (CVRWQCB, 2012). The Cawelo Water District sets water quality goals that comply with requirements established by the CVRWQCB in the Tulare Lake Basin Plan. However, these requirements do not include monitoring for constituents specific to, or indicative of, hydraulic fracturing (CVRWQCB, 2012).

2.6.2.4. Treatment and Reuse of Oil and Gas Industry Wastewater

Comprehensive data on current practices applied in California for the treatment of produced water before beneficial reuse are not available. However, in general, the treatment of produced water has been the subject of intensive investigation and standard treatment practices have evolved for the reuse of produced water (e.g., Federal Remediation Technologies Roundtable, 2007). Treatment of constituents commonly found in produced water (e.g., oil and grease, dissolved solids, suspended particles, bacteria, etc.) is generally well documented (Arthur et al., 2005; Drewes, 2009; Fakhru'l-Razi et al., 2009; Igunnu and Chen, 2012; M-I SWACO, 2012). We are unaware of any studies that examine whether commonly used produced water treatment systems would effectively remove hydraulic fracturing chemicals (particularly organic chemicals) that might be found in produced water from stimulated wells.

We evaluated the potential effectiveness of various chemical, physical, and biological treatment technologies commonly used for produced water treatment in California for removing well stimulation chemicals (Appendix 2-C). Results of the analysis indicate that there is no one treatment technology that can independently treat all categories of well-stimulation-fluid additives, but that treatment trains (systems of combined processes in series) could probably be developed to treat most stimulation chemicals known to be used in California. For example, the San Ardo Oil Field Water Management Facility, located in the upper Salinas Valley in Monterey County, treats produced water through several pretreatment processes, followed by a two-pass reverse osmosis (RO) system before use for environmental purposes and groundwater recharge (Figure 2.C-1)—whereas the Kern Front No. 2 Treatment Plant in northern Kern County treats produced water by gravity separation, followed by air flotation with coagulants and mechanical agitation for use in irrigation (Figure 2.C-2). Based on the analysis in Appendix C, the treatment train at

San Ardo would be expected to effectively remove all well stimulation chemicals from influent streams, while the Kern Front No. 2 Treatment Plant would not be expected to remove most chemicals associated with well stimulation operations. In summary, the most common simple treatment trains, for example oil separation followed by filtration, are not expected to be effective at removing most well stimulation chemicals, but more complex treatment trains, potentially including RO, may be effective.

Reuse of produced water for irrigated agriculture, groundwater recharge, or environmental flows is an attractive idea, especially in the face of drought. For a successful reuse program, it will be necessary to identify beneficial uses for reclaimed wastewater from oil and gas production, identify the water quality objectives to support that use, and identify what parameters of the produced waters exceed these water quality objectives. Treatment and reuse of produced water from fields with stimulated wells should consider the presence of well-stimulation-fluid chemicals and their breakdown products as part of this evaluation.

2.6.2.5. Disposal of Produced Water in Sanitary Sewer Systems

There is no evidence that produced water from stimulated wells in California is currently being disposed of in sanitary sewer systems. Statewide, however, an estimated 7 million m^3 and 4 million m^3 (5,700 and 3,200 acre-feet) of produced water was disposed of in sanitary sewer systems in 2012 and 2013, respectively, and some of this has occurred in fields where wells have been stimulated (e.g., Wilmington Oil Field in Los Angeles County and a small amount from the Lost Hills Oil Field and Midway-Sunset Oil Field in Kern County). Oil and gas well operators that discharge produced water into sanitary sewers are required by the sanitation districts to obtain pretreatment permits. Pretreatment of produced water is typically minimal—consisting primarily of oil and water separators, followed by clarification and sometimes air stripping or flotation—and does not remove most chemicals associated with well-stimulation operations.

Additionally, sewage treatment plants are not typically equipped to handle produced water, potentially disrupting the treatment process and discharging salt and other contaminants into the environment. In Pennsylvania, for example, the high salt content of oil and gas wastewater resulted in increased salt loading to Pennsylvania rivers (Brantley et al., 2014; Kargbo et al., 2010; Vidic et al., 2013; Wilson and VanBriesen, 2012). Ferrar et al. (2013) identified concentrations of some chemicals, including barium, strontium, bromides, chlorides, total dissolved solids, and benzene, in treated effluent that exceeded drinking water quality criteria. Similarly, Warner et al. (2013a) studied the effluent from a brine treatment facility in Pennsylvania and found that TDS from the effluent led to an increase in salts downstream, despite significant reduction in concentrations due to the treatment process and dilution from the river. Moreover, radium activities in the stream sediments near the point of discharge were 200 times higher than in upstream and background sediments, and were above radioactive waste disposal thresholds. State regulators in Pennsylvania subsequently discouraged the practice of discharging waters recovered from fracturing operations to sanitary sewer systems due to water quality

concerns, although some discharge into these facilities has continued. Much of the research on disposal to these systems has focused on the produced water constituents and has not specifically addressed the fate of stimulation chemicals commingled with produced water.

2.6.2.6. Leakage through Hydraulic Fractures

One concern related to subsurface leakage through hydraulic fractures is the degree to which induced fractures may extend beyond the target formation to connect to overlying protected groundwater, or to other natural or man-made pathways such as faults, natural fractures, or abandoned wells. Many studies, which are discussed in detail below, reference stimulation activities conducted at significant depth, and thus it has been generally assumed that fractures cannot directly intercept groundwater resources. The situation in California is notably different, due to the shallow depths of fracturing (Volume I, Chapter 3). Additional data about fracture geometry and depths are starting to emerge from the well completion reports that are now being submitted to DOGGR by operators.

The completion reports have data for the horizontal and vertical extent of stimulation, which are reported as "Stimulation Length" and "Stimulation Height." For this assessment, we analyzed the reported stimulation length and height, and calculated the depth (from the surface) to the top of the stimulation using data reported for 499 hydraulic fracturing treatments from a total of 506 well completion reports that were available as of December 15, 2014. The depth from the surface to the top of the stimulation was calculated as:

$$\frac{\text{TVD Wellbore Start+TVD Wellbore End}}{2} - \frac{\text{Stimulation Height}}{2}$$

where "TVD Wellbore Start" and "TVD Wellbore End" refer to the true vertical depths at the top and bottom of the treatment interval in the well, respectively.

This calculation is based on the assumption that the reported stimulation geometries are accurate. It is also assumed that stimulation propagates equally in both vertical directions from the midpoint of the treatment interval, and so does not account for asymmetrical vertical growth relative to the well interval treated. We also assume that the midpoint of the stimulation height occurs at the midpoint of the true vertical depth of the treated wellbore interval. The original dataset had to be modified to create consistent data formats. Only hydraulic fracturing treatments were considered; data for the seven acid matrix treatments were excluded. The distribution of these depths is shown in Figure 2.6-4.

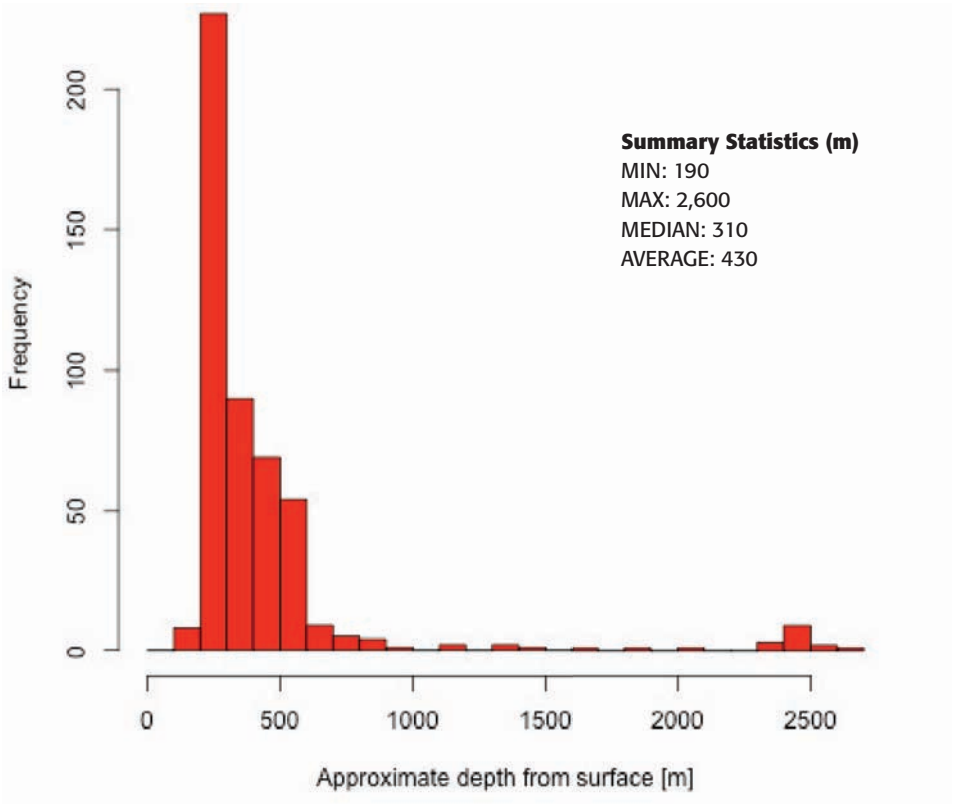
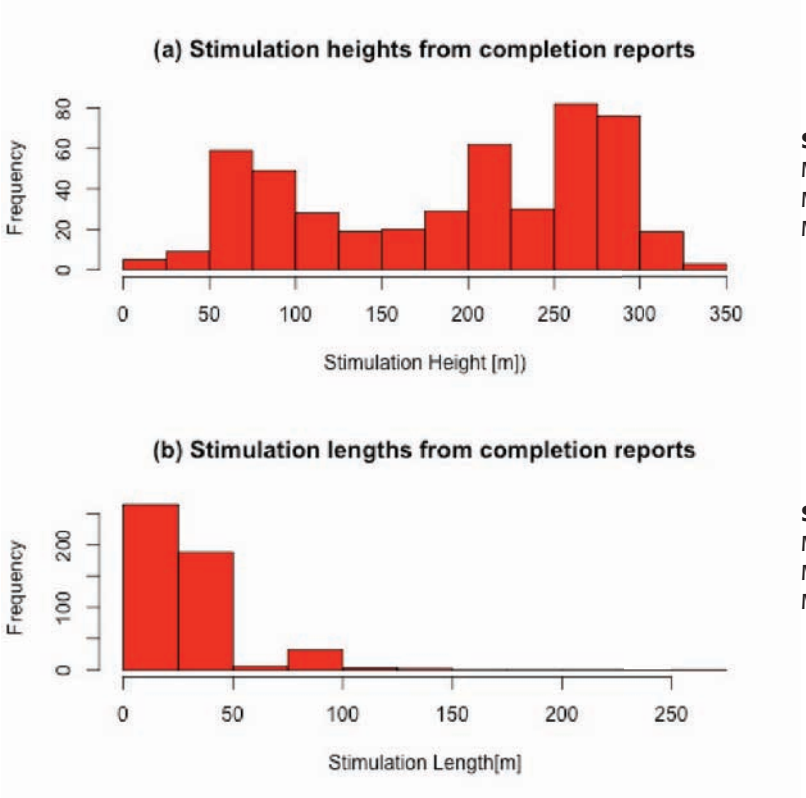


Figure 2.6-4. The approximate depth (from the surface) of the top of the hydraulic fracturing stimulations, (calculated by subtracting half the stimulation height from the midpoint of the wellbore treatment interval). Data source: Completion reports submitted to DOGGR as of Dec 15, 2014.

The data show that the true vertical depths to the top of the producing horizon in which the fracturing is induced are mostly shallow, ranging from 200 to 300 m (650 to 1,000 ft), and that in approximately half the operations, fracturing can extend to depths less than 300 m (1,000 ft) from the surface. This result is consistent with an earlier analysis that found the top of the fracturing interval in about half the operations to be less than 300 m (1,000 ft) deep (Volume I, Chapter 3). The shallow depths of fracturing raise concern about the possibility that out-of-zone fractures may directly intercept protected groundwater resources. Additional research is needed to determine how often this occurs, if at all, and the consequences if it does occur.

Most of the reported stimulation heights are between 50 m and 300 m (165 ft and 1,000 ft), while stimulation lengths in lateral directions are typically less than 50 m (165 ft) (Figure 2.6-5); however, the data for stimulation dimensions are inferred from unsubstantiated industry calculations. Based on the data submitted to DOGGR, it appears as though stimulations due to fracturing are oriented more vertically than horizontally (Figure 2.6-6).



Summary statistics (m)
MIN: 16
MAX: 336
MEDIAN: 211

Summary statistics (m)
MIN: 15
MAX: 266
MEDIAN: 23

Figure 2.6-5. Distribution of (a) stimulation heights and (b) stimulation lengths in California. Data source: Completion reports submitted to DOGGR as of December 15, 2014.

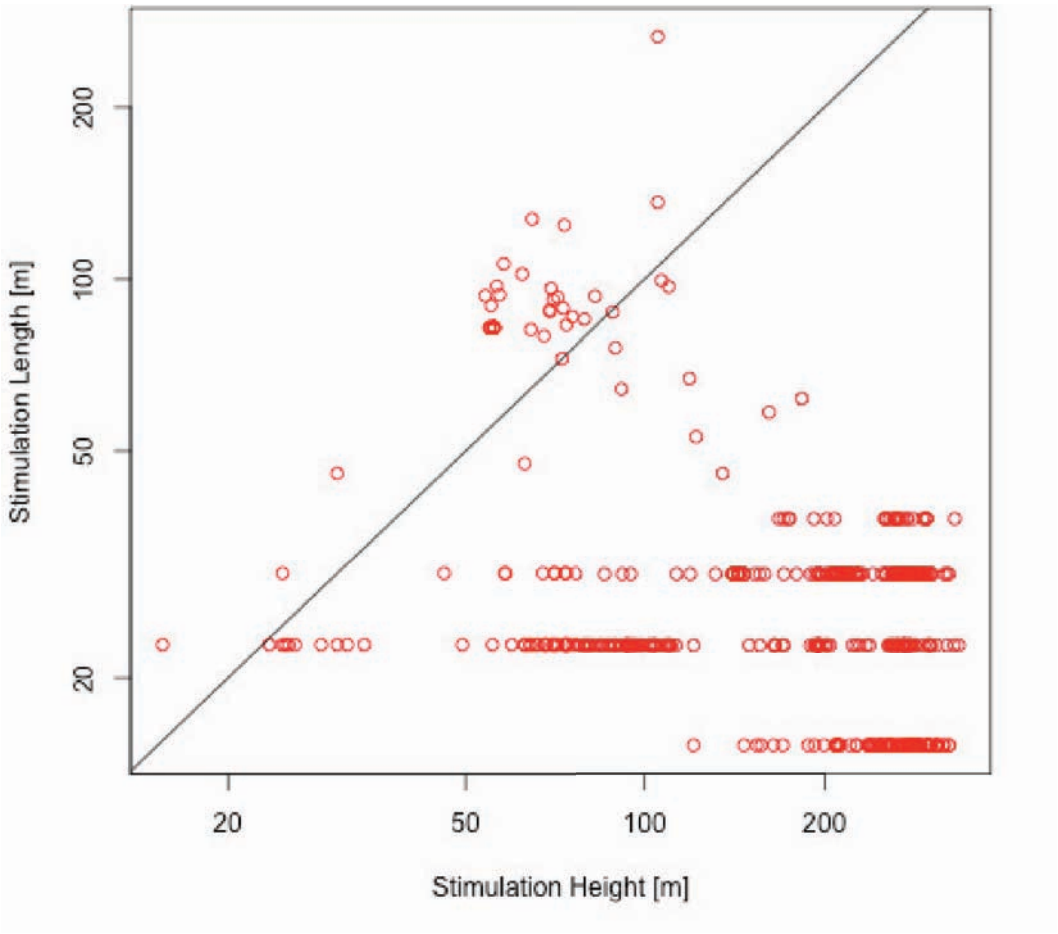


Figure 2.6-6. Comparison of stimulation heights with stimulation lengths for fracturing operations show that stimulations extend more vertically than horizontally. The solid line represents the 1:1 relationship; axes are in log scales. Data source: Completion reports submitted to DOGGR as of December 15, 2014.

The accuracy of the reported data on fracture geometries is unknown, given that operators do not report the methods for calculating the stimulation height and length. Furthermore, examination of hundreds of the well records that record hydraulic fracturing operations indicates operations consisting of only one stage are less than one quarter of all operations. However, all the completion reports indicate only one stage per well. It is unlikely such a substantial change in practice occurred at the same time that mandatory reporting commenced. It is more likely operators are reporting all fracturing stages within a well as one stimulation, and misreporting the number of stages in the well. Consequently, it is not possible to draw definite conclusions from these data regarding the length versus height, and consequently orientation, of fractures from individual stages. However, four-fifths of the reports list a stimulation height that is the same or less than the vertical height of the treatment interval in the well, suggesting almost all fracturing in California is horizontal. This is at odds with the other data submitted by operators (Figure

2.6-6), and with the predominance of vertical fracturing reported in literature regarding the reservoirs in the San Joaquin Basin, where most hydraulic fracturing occurs (Volume III, Chapter 5).

Basic work on understanding induced fractures spans decades (Hubbert and Willis, 1972; Nordgren, 1972; Perkins and Kern, 1961), but literature on studies conducted in California is limited. Emanuele et al. (1998) measured the orientation of fractures resulting from tens of stages in three horizontal wells in the Lost Hills field at a depth of approximately 600 m (2,000 ft) using surface tiltmeter measurements, along with some subsurface tiltmeter measurements. The orientation of all the fractures was within 10 degrees of vertical. Allan et al. (2010) reported on testing of longitudinal versus transverse fracturing in horizontal wells at a depth of approximately 300 m (1,000 ft) in the South Belridge field, reporting that the fractures were likely vertical as indicated by surface and downhole tiltmeter measurements.

However, both fracture *orientation* and fracture *extent* must be evaluated. In work performed outside of California, where fracturing occurs generally much deeper and with less injection volumes, fracture orientations have been different. Flewelling and Sharma (2014) observed that shallow formations are more likely to fracture horizontally rather than vertically, regardless of fracture extent, and capped potential fracture vertical extent at 600 m (2,000 ft) or less. Fisher and Warpinski (2012) compared microseismic data on fracture extent and found that fractures in shallower formations (<1,200 m, or 3,900 ft) have a greater horizontal component, and that deep hydraulic fractures should not be vertically extensive such as to contact shallow aquifers. This paper, however, also stated that earlier work found orientations dependent on the unique stress profiles and rock fabric of a given location (Walker et al., 2002). Coupled flow-geomechanical modeling (Kim and Moridis, 2012) found inherent physical limitations to the extent of fracture propagation—for example, the presence of overlying confining formations may slow or stop fracture growth in the vertical direction, thus containing fractures within the reservoir (Kim et al., 2014). Likewise, Davies et al. (2012) find that the majority of induced fractures (with data focused on high-volume fracturing operations in the Barnett Shale in Texas) range from less than 100 m (330 ft) to about 600 m (2,000 ft) in vertical extent, with approximately a 1% probability of a fracture extending 350 m (1,100 ft) vertically. This leads to a suggested minimum separation of 600 m (2,000 ft) between shale reservoirs and overlying groundwater resources for high-volume fracturing operations conducted in deeper formations elsewhere in the country (King, 2012). For comparison, completion reports show that the fractures in California can be as shallow as 200 m (650 ft) from the surface, which is much less than this suggested minimum, and thus a predominantly vertical fracture orientation increases the likelihood of encountering protected groundwater. More studies are needed to evaluate the fracturing behavior, fracture propagation, and the orientation of fractures relative to reservoir depth in typical hydraulic fracturing operations in California.

2.6.2.7. Leakage through Failed Inactive (Abandoned, Buried, Idle or Orphaned) Wells

Oilfield gas and formation water may reach the surface through degraded and leaking wellbores. Regions with a history of oil and gas production such as California have a large number of inactive (abandoned, buried, idle or orphaned) wells, many of which may be undocumented, unknown, and either degraded, improperly abandoned, or substandard in construction. Fractures created during hydraulic fracturing can create connectivity to inactive wells, particular in high-density fields such as found in the Kern County in California. However, the inactive wells have to fail (for example, due to degradation of cement or casings), and sufficient driving forces must be present for leakage of gas or formation water to occur through inactive wells.

In California, there are more inactive than active wells. Of a total of about 221,000 wells listed in the DOGGR GIS wells file, nearly 116,000 wells have been plugged and abandoned according to state standards. Nearly 1,800 wells are "buried," i.e., older wells which have not been abandoned to standards and whose location is approximate. Finally, the status of 388 wells is unknown, i.e., these are pre-1976 wells whose status is only on a hard copy file. Approximately 53% of the abandoned wells are located in Kern County. DOGGR also has an idle and orphan well program.[10] An idle well is defined as "a well that has not produced oil and/or gas or has not been used for fluid injection for six consecutive months during the last five years". An orphaned well is an abandoned well that has no owner. The DOGGR idle wells inventory lists, as of December 2014, a total of 21,347 idle wells, although this number differs from the number of idle wells reported in the GIS wells file (13,450 wells). DOGGR also lists 110 currently orphaned wells in California and an additional 1,307 hazardous orphaned wells were plugged by DOGGR between 1977 and 2010.

The accuracy of the locations of inactive wells listed in the DOGGR GIS wells file has not been independently verified, and the actual counts of buried wells may be underestimated, since there could be historical wells whose location is unknown. The conditions of the abandoned, plugged, and buried wells are unknown. Under SB 4, operators are required to identify plugged and abandoned wells that may be impacted by the stimulation operation while applying for a permit, but are not required to test their condition. Idle wells are required to be tested periodically to ensure that they are not impacting surface and groundwater by the DOGGR Idle and Orphan well program. The type of testing required is not specified, and can be as simple as a fluid-level survey or may be a more complicated well-casing mechanical integrity test.

Old and inactive wells are a problem in many other states. For example, in Pennsylvania, there are thousands of wells from previous oil and gas booms, with 200,000 dating from before formal record-keeping began and 100,000 that are essentially unknown (Vidic

10. See http://www.conservation.ca.gov/dog/idle_well/Pages/idle_well.aspx

et al., 2013), and increasing attention has been given to assessing these as transport pathways. Abandoned wells have also been attributed as causes for contamination of groundwater in Ohio and Texas and programs to locate, assess, and cap previously abandoned wells have been subsequently initiated in those states (Kell, 2011). Chilingar and Endres (2005) documents a California incident in 1985, where well corrosion at shallow depths led to casing failure of a producing well and the subsequent migration of gas via a combination of abandoned wells and fault pathways to a Los Angeles department store basement, resulting in an explosion. The paper also documents multiple cases of gas leakage from active oil fields and natural gas storage fields in the Los Angeles Basin and elsewhere, with the most common pathway being gas migration through faulted and fractured rocks penetrated by abandoned and leaking wellbores, many of which predate modern well-casing practice and are undocumented or hidden by more recent urban development. While stimulation technologies are not implicated in these events, they illustrate the real possibility of degraded abandoned wells as pathways.

The hazards of degraded abandoned wells are not just limited to their proximity to stimulated wells, but are also relevant to the issue of disposal of wastewater from stimulated wells by injection into Class II wells. A 1989 U.S. Government Accountability Office (GAO) study of Class II wells across the United States (U.S. GAO, 1989) found that one-third of contamination incidents were caused by communication with an improperly plugged abandoned oil and gas well. Current UIC program permitting requirements require a search for abandoned wells within a quarter mile of a new injection wellbore, and plugging and remediation of any suspect wellbores (40 CFR 144.31, 146.24). However, Class II wells operating prior to 1976 are exempt from this requirement. Thus, 70% of the disposal wells reviewed were pre-existing, grandfathered into the program, and allowed to operate without investigating nearby abandoned wells (U.S. GAO, 1989).

2.6.2.8. Failure of Active Production, Class II, and Other Wells

Operating wells (whether used for production or injection) can serve as leakage pathways for subsurface migration. Pathways can be formed due to inadequate design, imposed stresses unique to stimulation operations, or other forms of human error. Class II deep injection wells with casing or cement inadequacies would also have similar potential for contamination as a failed production well or a well that fails due to stimulation pressures. Examples of potential subsurface releases through wells are illustrated in Figure 2.6-2.

Stimulated wells may be subject to greater stresses than non-stimulated wells, due to the high-pressure stimulation process and the drilling practices used to create deviated (often horizontal) wells (Ingraffea et al., 2014). During hydraulic fracturing operations, multiple stages of high-pressure injection may result in the expansion and contraction of the steel casing (Carey et al., 2013). This could lead to radial fracturing and/or shear failure at the steel-concrete or concrete-rock interfaces, or even separation between the casing and the cement. These gaps or channels could serve as pathways, or (as a worst-case) create connectivity between the reservoir and overlying aquifers. Current practice

does not typically use the innermost casing as the direct carrier of stimulation fluids (or produced fluids and gases). Additional tubing (injection tubing or production tubing) is run down the innermost well casing without being cemented into place, and thus carries the stresses associated with injection. However, less complex stimulation treatments, such as some California operations, may not require such additional steps, and some fracturing operations may use the innermost casing to carry the fracturing fluids and the pressures associated with the fracturing operation.

In addition, several mechanisms—such as surface subsidence, reservoir compaction or heaving, or even earthquakes—can lead to well impairment due to casing shear (Dussealt et al., 2001). The diatomite formations in Kern County are highly porous and compressible, and hence are particularly susceptible to depletion-induced compaction. For example, several wells failed in the 1980s in Belridge (at a peak rate of 160 wells per year) following years of active production enabled by stimulation, which led to reservoir depletion and subsidence (Fredrich et al., 1996; Dussealt et al., 2001). Waterflood programs were then initiated to counter the subsidence, which led to much lower rates of well failure in the late 1990s of around 2–5% of active wells per year or approximately 20 wells per year (De Rouffignac et al., 1995; Fredrich et al., 1996; Dussealt et al., 2001). The current situation with groundwater overdraft in the southern San Joaquin Valley may pose an added risk to wells in the region due to subsidence. Earthquakes can also lead to casing shear; for example, hundreds of oil well casings were sheared in the Wilmington oil field in Los Angeles during five or six earthquakes of relatively low magnitude (M2 to M4) during a period of maximum subsidence in the 1950s (Dussealt et al., 2001).

Failures in well design and construction may allow migration of gas and fluids from the reservoir, or from shallower gas and fluid-bearing formations intersected by the wellbore. Wells can thus serve as pathways for gas migration to overlying aquifers or even to the surface (Brufatto et al., 2003; Watson and Bachu, 2009). Multiple factors over the operating life of a well may lead to failure (Bonett and Pafitis, 1996; Brufatto et al., 2003; Carey et al., 2013; Chilingar and Endres, 2005; Dusseault et al., 2000; Watson and Bachu, 2009); however, the most important mechanism leading to gas and fluid migration is poor well construction or exposed (or uncemented) casing (Watson and Bachu, 2009). A surface casing may not protect shallow aquifers, particularly if the surface casing does not extend to a sufficient depth below the aquifer (Harrison, 1983; 1985).

Watson and Bachu (2008) also noted that deviated wellbores, defined as “any well with total depth greater than true vertical depth,” show a higher occurrence of gas migration than vertical wells, likely due to the challenges of deviated well construction increasing the likelihood of gaps, bonding problems, or thin regions in the cement that could create connectivity to other formations. In a review of the regulatory record, Vidic et al. (2013) noted a 3.4% rate of cement and casing problems in Pennsylvania shale-gas wells (that all had some degree of deviation) based on filed notices of violation. Pennsylvania inspection records, however, show a large number of wells with indications of cement/casing impairments for which violations were never noted, suggesting that the actual rate of occurrence could be higher than reported (Ingraffea et al., 2014; Vidic et al., 2013).

The bulk of the peer-reviewed work on contaminant migration associated with stimulation focuses on the Marcellus Shale gas plays of Pennsylvania, West Virginia, Ohio, and New York. This literature features a number of competing studies that focus on fracturing-derived pathways, but also provides a robust debate on the role of deteriorated or poorly constructed wells. A sampling study by Osborn et al. (2011a) and Jackson et al. (2013a) noted that methane concentrations in wells increased with increasing proximity to gas wells, and that the sampled gas was similar in composition to gas from nearby production wells in some cases. Follow-up work by Davies (2011) and Schon (2011) found that leakage through well casings was a better explanation than other fracturing-related processes (also see Vidic et al., 2013). Most recently, other sampling studies (Darrah et al., 2014; Molofsky et al., 2013) found gas compositions in wells with higher methane, ethane, and propane concentrations sometimes match Marcellus gas, likely through leaks in well casings; in other instances, they do not match the gas compositions in the Marcellus Shale, suggesting that intermediate formations are providing the source for the additional methane, probably due to insufficient cementing in poorly constructed wells. The Darrah et al. (2014) study in particular identifies eight locations in the Marcellus (and also for one additional case in the Barnett Shale in Texas) where annular migration through/around poorly constructed wells is considered the most plausible mechanism for measured methane contamination of groundwater.

In California, a 2011 report that studied the over 24,000 active and 6,900 inactive injection wells in the state found that, while procedures were in place to protect freshwater resources, other water resources (with higher levels of dissolved components, but not considered saline) may be at risk due to deficiencies in required well-construction practices (Walker, 2011). In California, there has been little to no investigation to quantify the incidence and cumulative hazard or indicators of wellbore impairment. However, studies from other oil- and gas-producing regions indicate that wellbores have the potential to serve as leakage pathways in California, and need to be investigated.

2.6.2.9. Leakage through Other Subsurface Pathways (Natural Fractures, Faults or Permeable Formations)

Several modeling studies have attempted to elucidate mechanisms of subsurface transport in fractured formations through numerical simulation, although in all cases some simplification of subsurface properties was necessary, since subsurface heterogeneity is both difficult to quantify and to represent in a model. A well-publicized study by Myers (2012) found potential transport between fractured reservoirs and an overlying aquifer, but did so using a highly simplified flow model regarded as unrepresentative (Vidic et al., 2013). Two recent studies modeled higher-permeability pathways intersecting reservoir boundaries. Modeling work by Kissinger et al. (2013) suggests that transport of liquids, fracturing fluids, or gas is not an inevitable outcome of fracturing into connecting pathways. Modeling work by Gassiat et al. (2013) found that migration of fluids from a fractured formation is possible for high-permeability fractures and faults, and for permeable bounding formations, but on 1,000-year timeframes. Flewelling and Sharma

(2014) conclude that upward migration through permeable bounding formations, if possible at all, is likely an even slower process operating at much longer timescales (in their estimate, ~1,000,000 years). Additional modeling studies on gas transport through fractures in shale formations, suggest gas escape is likely to be limited in duration and scope for hydrostatic reservoirs (Reagan et al., 2015; U.S. EPA 2015b). Such studies require corroborating field and monitoring studies to provide a complete view of the possible mechanisms and outcomes.

Sampling and field studies have also sought evidence of migration via fractures, but the bulk of the peer-reviewed work focuses on the Marcellus Shale, and no such studies have been conducted in California. A key conclusion is that pathways and mechanisms are difficult to characterize, and the role of fracturing or transport through fractures has not been clearly established. Methane concentrations in wells increase with proximity to gas wells, and the gas is similar in composition to gas produced nearby (Jackson et al., 2013a; Osborn et al., 2011a), but evidence of contamination from brines or stimulation fluids was not found (Jackson et al., 2011; 2013a; Osborn et al., 2011b), suggesting that gas and liquid migration may not be driven by the same processes. The most recent sampling studies (Darrah et al., 2014; Molofsky et al., 2013) conclude that migration through poorly constructed wells is a more likely scenario than fracture-related pathways. Work on the properties of gas shales (Engelder et al., 2014) proposed that a "capillary seal" would restrict the ability of fluids to migrate out of the shale, but many reservoirs in California contain more mobile water, reducing this possibility.

Fault activation resulting in the formation of fluid pathways is an additional concern when stimulation operations occur in faulted geologies, such as in California (Volume II, Chapter 4). Fault activation is a remote possibility for faults that can admit stimulation fluids during injection (Rutqvist et al., 2013), possibly increasing the permeability of previously sealed faults or creating new subsurface pathways analogous to induced fractures (possibly on a larger scale). Fault activation could also give rise to (small) micro-seismic events, but fault movement is limited to centimeter scales across fault lengths of 10 to 100 m (33 to 330 ft) (Rutqvist et al., 2013). Chilingar and Endres (2005) document a California incident in which the migration of gas via permeable faults (among other pathways) created a gas pocket below a populated area in Los Angeles and resulted in an explosion. While the incident was not related to stimulation operations, it shows how naturally faulted geologies can provide pathways for migration of gas and fluids.

2.6.2.10. Spills and Leaks

Oil and gas production involves some risk of surface or groundwater contamination from spills and leaks. Well stimulation, however, raises additional concerns, owing to the use of chemicals during the stimulation process, the generation of wastewaters that contain these chemical additives (as well as formation brines with potentially different compositions from conventional produced waters), and the increased transportation requirements to haul these materials to the well and disposal sites.

Surface spills and leaks can occur at any time in the stimulation or production process. Spills and leaks can occur during chemical or fluid transport, pre-stimulation mixing, during stimulation, and after stimulation during wastewater disposal. In addition, storage containers used for chemicals and well stimulation fluids can leak (Figure 2.6-1). Releases can result from tank ruptures, piping failures, blowouts, other equipment failures and defects, overfills, fires, vandalism, accidents, or improper operations (NYSDEC, 2011). Additionally, natural disasters (e.g., floods or earthquakes) may damage storage and disposal sites or cause them to overflow. For example, major flooding in 2013 damaged oil and gas operations in northeast Colorado, spilling an estimated 180 m^3 (48,000 gal) of oil and 160 m^3 (43,000 gal) of produced water (COGCC, 2013). Once released, these materials can run off into surface water bodies and/or seep into groundwater aquifers.

In California, any significant or threatened release of hazardous substances must be reported to California Office of Emergency Services (OES) (19 CCR 2703(a)). According to California state law, the reporting threshold for chemical spills varies by chemical. There is no specific reporting threshold for produced water, although any release must still be reported to the appropriate DOGGR district office (Cal. Code Regs. tit. 14, § 1722(i)). All spills into or on state waters must also be reported to OES. OES maintains a database with information on the location, size, and composition of the spill; whether the spill impacted a waterway; and the cause of the spill. OES then conveys information on spills originating from or associated with an oil or gas operation to DOGGR, and DOGGR staff enters these data into the California Well Information Management System (CalWIMS) database. In some cases, DOGGR works with companies after a spill has occurred to obtain additional information and, as a result, some of the data within DOGGR and OES spills databases are inconsistent. For this analysis, we relied on the OES database; however, we discuss the need to standardize these databases in Section 2.9. It is of note that operators are not required to report whether a spill was associated with well stimulation, nor do the reports contain an American Petroleum Institute (API) number, which could be used to link the spill to stimulation records.

Between January 2009 and December 2014, a total of 575 produced water spills were reported to OES, or an average of about 99 spills annually. The majority (55%) of these spills occurred in Kern County, followed by Los Angeles (16%), Santa Barbara (13%), Ventura (6%), Orange (3%), Monterey (2%), and San Luis Obispo (1%), and Sutter (1%) counties. Nearly 18% of these spills impacted waterways.

Chemical spills were also reported in California oil fields, including spills of chemicals typically used in well stimulation fluids, e.g., hydrochloric, hydrofluoric, and sulfuric acids. Between January 2009 and December 2014, a total of 31 chemical spills were reported to OES. Forty-two percent of these spills were in Kern County, followed by Los Angeles (16%), Sonoma (16%), and Lake (3%) counties. Chemical spills represent about 2% of all reported spills attributed to oil and gas development during that period. None of the reported spills contained chemicals used for hydraulic fracturing in California.

Nine of the chemical spills were of acid. This suggests that acid spills are relatively infrequent, representing less than 1% of all reported spills attributed to oil and gas development during that period. Among these was a storage tank at a soft water treatment plant containing 20 m^3 (5,500 gal) of hydrochloric acid in the Midway-Sunset Oil Field in Kern County that ruptured violently, releasing the acid beyond a secondary containment wall. No injuries or deaths were associated with this or any other acid spill. While 10% of the chemical spills were reported to enter a waterway, none of the acid spills was reported to enter a waterway.

2.6.2.11. Operator Error During Stimulation

Human error during the well completion, stimulation, or production processes could also lead to contamination of groundwater. Operator error could create connectivity to other formations that could serve as transport pathways. For example, poor monitoring or control of the fracturing operation could lead to creation of fractures beyond the confines of the reservoir, or increase the extent of fractures beyond desired limits. Such errors, if not found and corrected, could lead to unexpected migration of fluids, or in the case of the high-density well siting often found in California, connectivity between wells that impacts production activities themselves. Fracturing beyond the reservoir bounds due to operator error may also be of particular concern in the case of the shallower fracturing operations that may occur in California.

An example of operator error during stimulation is a 2011 incident in Alberta, Canada (ERCB, 2012), where an overlying formation was inadvertently fractured due to misreading of well fluid pressures, and stimulated fluids were injected into a water-bearing strata below an aquifer. Immediate flowback of fracturing fluids recovered most of the injected volume, and monitoring wells were installed into the aquifer and an overlying sandstone layer. A hydraulic connection between the fractured interval and the overlying aquifer was not observed, but groundwater samples contained elevated levels of chloride, benzene, toluene, ethylbenzene, and xylenes (BTEX), petroleum hydrocarbons and other chemicals. The Energy Resources Conservation Board (ERCB) finding states that the incident presented “insignificant” risk to drinking water resources, but criticized the onsite crew’s risk management, noting there were multiple opportunities to recognize abnormal well behavior before the misplaced perforation.

2.6.2.12. Illegal Discharges

Illegal discharges of wastewater from oil and gas production have been noted in California for disposal in both unlined pits and via subsurface injection. For example, in July 2013, the CVRWQB issued a $60,000 fine to Vintage Production California, LLC, for periodically discharging saline water, formation fluids, and hydraulic fracturing fluid to an unlined pit in an area with good-quality groundwater (CVRWQCB, 2013). In a follow-up survey on disposal practices of drilling fluids and well completion fluids, the CVRWQCB identified several other illegal discharge incidents between January 2012 and December 2013

and fined the responsible operators (CVRWQCB, 2014). In a recent GAO review of the UIC programs in eight states, California agencies reported 9 and 12 instances of alleged contamination in 2009 and 2010, respectively, resulting from one operator injecting fluids illegally into multiple wells (U.S. GAO, 2014).

2.7. Impacts of Well Stimulation to Surface and Ground Water Quality

In this section, we review the potential impacts of well stimulation on water quality by examining results from the few sampling studies that have been conducted near hydraulic fracturing operations in the United States. Only one sampling study has been conducted near a hydraulic fracturing site in California (in Inglewood). Thus, we considered studies conducted in other regions of the United States where stimulation operations have occurred, including Pennsylvania, Texas, Ohio, Montana and North Dakota, to (1) examine incidents where water has been potentially contaminated due to oil and gas activities, to determine viable contaminant release mechanisms, and assess whether they apply to well stimulation activities in California; and (2) identify considerations for future sampling studies and monitoring programs in California, based on lessons learned from other states.

While some of the sampling studies have shown no evidence of water contamination associated with well stimulation, other studies found detectable impacts that were associated with, and allegedly caused by, well stimulation operations. A recently released draft report by the U.S. EPA did not find evidence of widespread, systemic impacts on drinking water resources in the United States, but found specific instances of impacts on drinking water resources, including contamination of drinking water wells. (U.S. EPA 2015b).

Notably, most groundwater sampling studies do not even measure stimulation chemicals, partly because their full chemical composition and reaction products were unknown. It should be noted that detecting groundwater contamination is more difficult than detecting surface water contamination because (1) the effects of contamination, the release mechanisms, and the transport pathways are less visible than at the surface; (2) there are many possible pathways and sources for contaminants to be present in groundwater, and definitively attributing contamination to well stimulation is difficult; and (3) impacts on groundwater may not be detected on relatively short time scales because of slow transport processes. These difficulties are compounded by the lack of baseline water quality data and monitoring to detect problems, as well as the lack of knowledge about the full composition of stimulation fluids and standard analytical methods to detect the chemical additives and their degradation products.

2.7.1. Studies that Found Evidence of Potential Water Contamination near Stimulation Operations

Several studies have found evidence of contamination due to stimulation, which were primarily attributed to surface spills or leaks of fluids used in hydraulic fracturing, or improper wastewater disposal (Table 2.7-1). For example, in 2007, flowback fluids

overflowed retention pits in Knox County, KY, killing or displacing all fish (including Blackside Dace, a federally threatened species), invertebrates, and other biota for months over a 2.7 km (1.7 mi) section of a local waterway (Papoulias and Velasco, 2013). In a study examining the effect of spills, the presence of known or suspected endocrine-disrupting chemicals used for hydraulic fracturing were measured at higher levels in surface and groundwater samples in drilling-dense areas of Garfield County, Colorado compared to nearby background sites with limited or no drilling activity (Kassotis et al., 2013). Surface water samples were collected from five distinct sites that contained from 43 to 136 natural gas wells within 1.6 km (1 mi) and had a spill or incident related to unconventional natural gas extraction within the previous six years.

There have been far fewer reports of groundwater contamination caused by subsurface release mechanisms, such as leakage through wells or leakage through hydraulic fractures or other natural permeable pathways. Most of the problems reported were due to the presence of methane gas or other formation water constituents in drinking water wells, and only three reports involve the possibility of contamination by hydraulic fracturing fluids. A recent study in Pennsylvania investigates an incident of contamination by natural gas in potable groundwater, where well waters were also observed to foam (Llewellyn et al., 2015). The authors used 2-D gas chromatography coupled to time-of-flight mass spectrometry (GCxGC-TOFMS) to identify an unresolved complex mixture of organic compounds in the aquifer that had similar signatures to flowback water from Marcellus shale-gas wells. The organic compounds were not present in nearby wells that were outside of the affected area. One compound in particular, 2nbutoxyethanol, which is not a natural constituent of water in the region, was identified in both the foaming waters and flowback water, although the study mentions that it could have also been used in drilling fluids. The authors conclude that, although they were not able to unambiguously prove a direct connection between shale gas operations and the detected organic chemicals in household waters, the timing and presence of similar compounds in “flowback/produced” waters suggest that the hydraulic fracture operations were a likely source (Llewellyn et al., 2015). The contaminant release mechanisms suggested by the authors include surface spills or subsurface leakage and transport through shallow fractures. The study also suggests that the most likely release mechanism for the natural gas was leakage through wells due to excessive annular pressures and lack of proper annular cement (Llewellyn et al., 2015).

There are two other unconfirmed potential groundwater contamination incidents attributed to subsurface leakage of hydraulic fracturing fluid within the United States (DiGiulio et al., 2011; U.S. EPA, 1987), but neither of them has been documented in a peer-reviewed publication (Brantley et al., 2014; Vidic et al., 2013). The first study is a U.S. EPA investigation in Pavilion, Wyoming, where surface storage and disposal of wastewaters was implicated in contamination of shallow surface water as discussed in Section 2.6. Initial results published in a draft report (DiGiulio et al., 2011) suggested that groundwater wells had been contaminated with various fracturing-fluid chemicals (glycols and alcohols) as well as methane, via flow from the stimulated reservoir to

groundwater. However, a follow-up study by the USGS involving resampling of the wells could not confirm some of these findings (Wright et al., 2012). The U.S. EPA is no longer working on this study, which is now being led by the State of Wyoming. The second reported incident of groundwater contamination is based on a U.S. EPA study focusing on operations in Ripley, West Virginia. In this case, a gel used as a constituent in fracturing fluids was reported to have contaminated a local water well located less than 330 m (1,000 ft) from a vertical gas well (U.S. EPA, 1987). Contaminant transport could have either occurred through four abandoned wells located near the vertical gas well during the fracturing process, or by contamination from the flush fluid used to remove loose rock cuttings prior to cementing (Brantley et al., 2014).

Several other studies note the presence of elevated levels of other contaminants in groundwater near stimulation operations. Some studies were unable to attribute the cause to stimulation, while others had to conduct several follow-on investigations to identify the contaminant release mechanisms. For example, some sampling studies found high concentrations of methane and other hydrocarbons in drinking-water wells in Pennsylvania, particularly those near hydraulic fracturing operations. Methane concentrations in the wells increased with increasing proximity to gas wells, but evidence of contamination from brines or fracturing fluids was not found (Dyck and Dunn, 1986; Jackson et al., 2011; 2013a; Osborn et al., 2011a; 2011b). There was significant debate about whether the high methane concentrations were naturally present, or a result of hydraulic fracturing operations. Additional sampling work (Jackson et al., 2013a) found ethane and propane, as well as methane, in water wells near Marcellus production locations. The studies determined that the methane was formed by thermogenic processes at depth (as would be expected for shale gas), and that the isotopic ratios of methane were found to be more consistent with non-Marcellus gas (Molofsky et al., 2013). The most recent sampling study (Darrah et al., 2014) again found isotopic and noble gas compositions inconsistent with a Marcellus (and thus a stimulation-derived) source, and identified eight locations where wells are considered the most plausible mechanism for measured methane contamination of groundwater—including incidents of migration through annulus cement (four cases), through production casings (three cases), and due to underground well failure primarily. In another study in the Marcellus, radon concentrations obtained from previously measured public data were found to increase in proximity to unconventional wells (Casey et al., 2015). Radon is a radioactive decay product of radium, and can dissolve and be transported through groundwater. The researchers also noted that concentrations increased in 2004 from previously fluctuating measurements, just preceding the Marcellus boom in 2005. However, the study had several shortcomings, including the lack of any detailed statistical measures for spatial association of radon with hydraulic fracturing operations, the lack of evidence showing any pathway that could cause an increase in radon concentrations, the reliance on unverified public data that were not necessarily submitted by accredited professionals, and other limitations that led to an acknowledgement by the authors stating that the study was exploratory.

Another study conducted in the Barnett Shale also illustrates the difficulty in tracing the source of the contaminants detected in groundwater near well stimulation operations shale (Fontenot et al., 2013), despite having historical and background water quality data. This study sampled 100 groundwater wells located in aquifers overlying the Barnett, and found that TDS concentrations exceeded the U.S. EPA Secondary Maximum Contaminant Level (MCL) of 500 mg L^{-1} in 50 out of 91 samples located within 3 km (1.9 mi) of gas wells, and that the maximum values of TDS near the wells were over three times higher than those from background wells located in areas that were unimpacted by fracturing enabled oil and gas development. Similarly, trace elements such as arsenic, barium, selenium, and strontium were found to be present at much higher levels compared to background or historical concentrations, and organics (methanol and ethanol) were detected in 29% of samples in private drinking-water wells. However, it was not possible to determine if hydraulic fracturing was the cause of the high TDS, trace element or organic concentrations, since historical, regional, and background values of these constituents were also high.

An extensive review of groundwater-contamination claims and existing data can be found in a report for the Ground Water Protection Council, focusing on Ohio and Texas groundwater-investigation findings during a 16-year study period from 1983 through 2008 (Kell, 2011). The study area and time period included the development of 16,000 horizontal shale gas wells with multistage fracturing operations in Texas and one horizontal shale gas well in Ohio. The report notes that, for the study period, no contamination incidents were found involving any stimulation activities including "site preparation, drilling, well construction, completion, hydraulic fracturing stimulation, or production operations at any of these horizontal shale gas wells." However, there were a total of 211 reported groundwater contamination incidents in Texas caused by other oil and gas activities. Seventy-five of these were caused by wastewater management and disposal activities, including 57 incidents due to improper storage of wastewater in surface containment pits. This practice has mostly been replaced by disposal via Class II injection wells that have a significantly better record of protecting groundwater resources than unlined pits (as discussed in Section 2.6). Other contamination incidents were related to orphaned wells (30 incidents, most of which were caused by inadequately sealed boreholes) and production activities (56 incidents that include 35 releases from storage tanks, 12 releases from flow lines or wellheads, 7 releases from historic clay-lined storage pits, and 2 releases related to well construction including an incident caused by a short surface casing that did not adequately isolate all groundwater). In Ohio, a total of 185 groundwater-contamination incidents were reported from other oil and gas activities, most of which occurred prior to 1993. Of these, 41 incidents were related to orphaned wells in abandoned sites, 39 incidents were caused by production-related activities (including 17 incidents of leaks from storage tanks or lines; 10 incidents caused by onsite produced water storage pits; 12 incidents caused due to well construction issues), and 26 incidents caused due to waste management and disposal activities. The report concludes that, although no documented links have been found implicating the fracturing process itself to contamination incidents, a regulatory focus on activities that could be linked to contamination is critical, along with documentation of hydraulic fracturing operations such that regulators can determine which processes put groundwater at risk.

Table 2.7-1. Examples of release mechanisms and contamination incidents associated with oil and gas activities in the United States.

Year	Location	Media Impacted	Contaminant	Attributed to Well Stimulation?	Evidence of Water Contamination	Release Mechanism	Operator	Source
1982	Jackson County, WV	Groundwater	Gelatinous material (fracturing fluid) and white fibers	Disputed	Fluid and fibers were found in the water sample from a well located <1,000 ft from a vertical gas well.	Unknown; 4 abandoned gas wells drilled in the 1940s are present within 1,700 ft of the new gas well and may have served as conduits for contamination.	Kaiser Gas Co.	Brantley, 2014; U.S. EPA, 1987
2007	Knox County, KY	Surface water	Flowback fluids	Yes	Flowback fluids were released directly into Acorn Fork. The incident killed or displaced all fish, invertebrates, and other biota for months over a 2.7 km section of the creek.	Retention pits overflowed.	Not known	Papoulias and Velasco, 2013
2007	Bainbridge Township, Geauga County, OH	Groundwater	Natural Gas	Yes	Natural gas seeped into an aquifer	Defective cement job in the well casing, compounded by operator error.	Ohio Valley Energy Systems Corp.	Ohio DNR, 2008
2009	Hopewell Township, Washington County, PA	Surface water	Wastewater	Yes	Fluid overflowed the impoundment's banks and ran over the ground and into a tributary of Dunkle Run.	Wastewater pit failure.	Atlas Resources LLC	PA DEP, 2010
2009	Dimock Township, Susquehanna County, PA	Surface water	8,000 gallons of water/liquid gel mixture used in hydraulic fracturing	Yes	Pollution in Stevens Creek and a nearby wetland resulted in a fish die-off.	Unknown	Cabot Oil & Gas	PA DEP, 2009
2011	Alberta, Canada	Groundwater	Fracturing fluids	Yes	Groundwater samples from monitoring wells found elevated levels of chloride, BTEX, petroleum hydrocarbons, and other chemicals.	Inadvertent fracturing of an overlying formation and injection of fluids into water-bearing strata below an aquifer.	Crew Energy Inc.	ERCB, 2012
2013	Colorado	Surface water	48,000 gallons of oil and 43,000 gallons of produced water	Yes		Spill during major flooding in 2013 damaged oil and gas operations.	Multiple	COGCC, 2013

Year	Location	Media Impacted	Contaminant	Attributed to Well Stimulation?	Evidence of Water Contamination	Release Mechanism	Operator	Source
2013	Kern County, CA		Saline water, formation fluids, and hydraulic fracturing fluid	Yes	None	Illegal discharge to an unlined pit.	Vintage	CVRWQCB, 2013
1983-2007	Ohio	Groundwater	Drilling contaminants-e.g., drill cuttings, crude oil, flowback, and produced water	Not known	The Ohio Division of Mines and Reclamation documented 185 groundwater contamination incidents caused by historic or regulated oilfield activities over a 25 year period	41 of the 185 incidents were caused by orphaned wells. 144 were caused by violations at permitted or regulated activities, including drilling & completion; production, on-lease transport, & storage; waste management & disposal; and plugging & site reclamation.	Not known	Kell, 2011
1993-2008	Texas	Groundwater	Multiple - e.g., drill cuttings, crude oil, flowback, and produced water	Not known	The Texas Railroad Commission documented 211 incidents of groundwater contamination caused by historic or regulated oilfield activities over the 16 year period.	75 incidents resulted from waste management and disposal activities, including 57 legacy incidents caused by produced water disposal pits that were phased out starting in 1969 and closed by 1984. 56 incidents related to releases that occurred during production phase activities including storage tank or flow line leaks. 30 incidents were caused by orphaned wells or sites.	Not known	Kell, 2011
2010-2011	Weld County, CO	Groundwater	BTEX	Not known	77 reported surface spills impacting the groundwater	Spills due to 1. Equipment failure (47 spills); 2. corrosion/equipment failure (10 spills); 3. historical impact (i.e., discovery of a spill during inspection) (15 spills); 4. human error (3 spills); 5. Multiple leaks in dump line system (1 spill); and 6. unknown (1 spill).	Not known	Gross et al., 2013
2015	Pennysylvania	Groundwater	Methane, unresolved mixture of organic compounds (including 2-butoxyethanol)	Likely (but not unambiguously) caused by stimulation	Wells that had been previously contaminated with natural gas were observed to be foaming	Suggested release mechanisms are surface spills or release/transport through shallow fractures for the organic compounds. Methane was probably released through a different mechanism (through well casing)	Not known	Llewelyn et al., 2015

Year	Location	Media Impacted	Contaminant	Attributed to Well Stimulation?	Evidence of Water Contamination	Release Mechanism	Operator	Source
Not known	Kansas, Kentucky, Michigan, Mississippi, New Mexico, Oklahoma, and Texas.	Groundwater	Brine	Not known	A majority of the 23 cases were identified by users of the groundwater. The rest were identified by operators or EPA staff during monitoring operations or while reviewing injection records.	Improperly plugged oil and gas wells in the vicinity of Class II injection wells; leaks in Class II injection well casing; and Class II injection into a USDW.	Multiple	U.S. GAO, 1989
Not known	Pavillion, WY	Groundwater	Benzene, xylenes, gasoline-range organics, and diesel-range organics	Yes	High concentrations of hydraulic fracturing chemicals were found in shallow monitoring wells near surface pits.	Infiltration from storage/disposal pits.	Encana Oil and Gas	DiGiulio et al., 2011; Folger et al., 2012
Not known	Pavillion, WY	Groundwater	Elevated concentrations of well stimulation and drilling chemicals	Disputed	Contaminants were detected in deep monitoring wells.	Thought to be related to gas production; however, the gas company disputes this claim.	Encana Oil and Gas	Folger et al., 2012
Not known	Saskatchewan, Canada	Groundwater	Methane	Not known	Elevated levels of methane found in groundwater associated with oil and gas fields.	Unknown; article suggests leakage along the exploration holes or migration through natural fractures.	Not known	Van Stempvoort et al., 2005
Not known	Texas	Surface water	Sediment	Not known	Study shows a strong correlation between shale-well density and stream turbidity.	Sediment runoff from wellpads.	Not known	Williams et al., 2008
Not known	Garfield County, CO	Surface and Groundwater	Endocrine-disrupting chemicals	Not known	Data suggest elevated endocrine-disrupting chemical activity in surface water and groundwater close to unconventional natural gas drilling operations.	Unknown	Not known	Kassotis et al., 2013
Not known	Northeastern PA and upstate NY	Groundwater	Methane	Not known	Study shows that, in active gas-extraction areas, average and maximum methane concentrations in drinking-water wells increased with proximity to the nearest gas well.	Unknown	Not known	Osborn et al., 2011a

2.7.2. Studies that Found No Evidence of Water Contamination Near Stimulation Operations

There are a few sampling surveys that have been conducted near stimulation operations in the United States. Many of these studies found no evidence of water contamination near stimulation operations, including the only sampling study conducted in California (Cardno ENTRIX, 2012).

The California study reviewed ten years of oil and gas production, including two years of well stimulation operations, at the Inglewood field in Los Angeles County. During this period, conventional hydraulic fracturing was conducted on 21 wells and high-volume hydraulic fracturing was conducted on two wells.[11] The Inglewood field is located in a populated area and underlies a freshwater formation that is regulated and monitored for water quality (Cardno ENTRIX, 2012). The study sampled the groundwater for pH, total petroleum hydrocarbons (TPH), benzene, methyl tertiary butyl ether (MTBE), total recoverable petroleum hydrocarbons (TRPH), total dissolved solids (TDS), nitrate, nitrite, metals, and biological oxygen demand (BOD), none of which is a specific analysis for chemicals used in hydraulic fracturing. The study concluded that there were no detectable impacts to groundwater quality due to the production or stimulation activities (Cardno ENTRIX, 2012). There was no evidence of migration of stimulation fluids, formation fluids, or methane gas during the study's timeframe, even though the formation contained faults and fractures connecting shallow formations to deeper formations (Cardno ENTRIX, 2012). Monitoring found no significant differences in pre-drilling and post-stimulation TDS levels. Trace metals were also sampled; arsenic was the only trace element that exceeded drinking water standards. However, the study mentions that arsenic is naturally present at high levels in Southern California, and concentrations were high in the monitoring wells before drilling (Cardno ENTRIX, 2012). Microseismic monitoring in the study indicated that fractures were contained within the hydrocarbon reservoir zone, extending to within no more than 2,350 m (7,700 ft) of the base of the freshwater zone (Cardno ENTRIX, 2012).

Outside of California, a few other studies have sampled water quality near hydraulically fractured wells in several regions, including the Marcellus Shale, Pennsylvania (e.g., Boyer et al., 2011; Brantley et al., 2014 and references therein; Siegel et al., 2015), the Fayetteville Shale, Arkansas (Warner et al., 2013b), the Barnett Shale, Texas (Fontenot et al., 2013), and the Bakken Shale, Montana/North Dakota (McMahon et al., 2015). Many of these studies, which largely examined groundwater quality, did not find statistically significant changes to the water quality of nearby groundwater wells after fracturing, when compared to baseline trends. The baseline trends were determined from samples

11. Conventional hydraulic fracturing uses water, sand, and additives to stimulate up to several hundred feet from the well and is typically applied in sandstone, limestone, or dolomite formations. High-volume hydraulic fracturing, by contrast, uses more fluids and is generally applied to shales rather than sandstones.

collected before drilling (if available) or alternatively from background sites with comparable geology and geochemistry that were considered to be relatively un-impacted by hydraulic fracturing operations.

In an extensive review, Brantley et al. (2014) found that stimulation in Pennsylvania has never been conclusively tied to an incident of water contamination, and that this could indicate that incidents are rare, and that contaminant release was diluted quickly. However, the review notes that it was not possible to draw firm conclusions due to several challenges, including (1) variable background concentrations of constituents in the groundwater and little knowledge of pre-existing contaminant concentrations; (2) lack of information about the timing and locations of drilling and production incidents; (3) withholding of water quality data from specific incidents due to liability concerns; (4) limited sample and sensor data for the constituents of concern; (5) possibility of sensor malfunction or drift. An extensive field study in the Marcellus Shale in southwest Pennsylvania was recently completed, but has not been peer-reviewed (NETL, 2014). The study combined microseismic monitoring of fracture propagation with sampling of produced gas and water from overlying conventional reservoirs. They found no evidence of gas, brine, or tracer migration into the monitored wells. A more recent study by Siegel et al. (2015) that examined an extensive industry dataset in the Marcellus Shale concluded that there was no correlation between the methane concentrations in domestic groundwater wells and hydraulic fracturing operations. However, the findings are questionable, due to the sampling strategy and techniques used (the samples were provided by the operator, Chesapeake Energy) and the lack of true baseline measurements.

In another study, 127 drinking water wells in the Fayettesville Shale were sampled and analyzed for major ions, trace metals, CH_4 gas content and its C isotopes ($\delta 13C_{CH4}$), and select isotope tracers (δ11B, Sr87/Sr86, δD, δ18O, $\delta 13C_{DIC}$). The data were compared to the composition of flowback samples directly from Fayetteville Shale gas wells. Methane was detected in 63% of the drinking-water wells, but only six wells had concentrations greater than 0.5 mg CH_4 L^{-1}. No spatial relationship was found between CH_4 and salinity occurrences in shallow drinking water wells with proximity to shale-gas drilling sites. They concluded, based on the analyses of geochemical and isotope data, that there was no direct evidence of contamination in shallow drinking-water aquifers associated with nearby stimulation operations (Warner et al., 2013b).

Another recent study conducted in the Bakken Shale sampled 30 domestic wells for major ions, nutrients, trace elements, 23 volatile organic compounds (VOCs); methane and ethane; and hydrocarbon-gas chemical (C1–C6) and isotopic (δ2H and δ13C in methane) compositions in 2013 (McMahon et al., 2015). This study also concluded that there had been no discernible effects of energy-development activities on groundwater quality, but also mentioned that the results had to be considered in the context of groundwater age and velocity. The groundwater age of the domestic wells ranged from <1,000 years to >30,000 years, based on ^{14}C measurements, and thus it was suggested that domestic wells may not be as well suited for detecting contamination from recent surface spills compared

to shallower wells screened near the water table. The horizontal groundwater velocities, also calculated from ^{14}C measurements, implied that the contaminants would only have travelled ~0.5 km (0.3 mi) from the source, and thus a more long-term monitoring plan was suggested to truly assess the effects of energy development in the area.

In general, it is difficult to detect groundwater contamination, especially in situations where there has not been adequate baseline water quality data or monitoring. In cases where some monitoring has been conducted, potential contaminant release may not have been detected for a number of reasons, such as inappropriate locations for testing, slow transport of contaminants, and high analyte detection limits.

2.7.3. Quality of Groundwater Near Stimulated Oil Fields in California

In order to know if poor groundwater quality is due to oil and gas development activities, the natural quality (background quality) of the groundwater needs to be understood. Contaminants associated with oil and gas development wastewaters, including TDS, trace elements, and NORM, occur naturally in California groundwater, and regional surveys are needed to establish background concentrations in areas of oil and gas development in order to determine how this activity is impacting groundwater. Elevated levels of trace elements, such as arsenic, boron, molybdenum, chromium, and selenium, have been measured in shallow groundwater in several regions in California (e.g., Schmitt et al., 2006; 2009). High levels of uranium, frequently exceeding U.S. EPA MCLs, have also been noted in the Central Valley, and are correlated with high bicarbonate concentrations in the groundwater (Jurgens et al., 2010). Similarly, several counties in California, including Santa Barbara, Ventura, and Kern counties, are considered to be in the U.S. EPA's radon zones 1 and 2, which indicates that they have a high to moderate potential of having radon in soils and groundwater (http://www.epa.gov/radon/zonemap.html).

In studies mostly conducted outside of California, methane concentrations in groundwater have been used as an indicator of unconventional oil and gas development impacts on household sources of drinking water, and as evidence of leakage around active and abandoned wells (Osborn et al., 2011a; Jackson et al., 2013a; Lleweyln et al., 2015). A survey of methane concentrations in Southern California identified eight high-risk areas where methane could pose a safety problem (Geoscience Analytical, 1986). These include the Salt Lake Oil field in Los Angeles; the Newport Oil field; the Santa Fe Springs Oil field; the Rideout Heights area of the Whittier Oil Field; the Los Angeles City Oil field; the Brea-Olinda Oil field; the Summerland Oil field; and the Huntington Beach Oil field. Similar surveys for methane have not been conducted in other parts of California.

Salt content, measured as TDS, is a critical limiting factor for the quality of groundwater. Uses of groundwater typically have a threshold over which higher TDS is aesthetically undesirable or will result in impairment. For instance, the taste of water may become unpleasant and plant growth reduced if TDS levels are above certain thresholds. For these reasons, there are various regulatory limits regarding water quality based on the total dissolved solids content, some of which are listed in Table 2.7-2.

Table 2.7-2. Some regulatory limits regarding total dissolved solids in water.

Maximum TDS (mg L^{-1})	Applicability	Enforceability	Overseeing Agency
500	Water supplied by a community water system	Not enforceable, but recommended	Federal EPA and CDPH
1,000		Upper limit[1]	CDPH
1,500		Short term limit[2]	
3,000	All surface and groundwater	Limit of suitability[3]	SWRCB
10,000	Groundwater	Protected, unless exempted[4]	Federal EPA, DOGGR, and SWRCB
TDS – Total Dissolved Solids			
EPA – Environmental Protection Agency			
CDPH – California Department of Public Health			
SWRCB – State Water Resources Control Board			
DOGGR – California Division of Oil, Gas and Geothermal Resources			

[1]Acceptable if it is neither reasonable nor feasible to provide more suitable water (Cal. Cod. Reg. § 64449)

[2]Acceptable only for existing systems on a temporary basis pending construction of new treatment facilities that will reduce the TDS to at least the upper limit or development of acceptable new water sources water (Cal. Cod. Reg. § 64449)

[3]All groundwater meeting this threshold, along with various other criteria, should be designated by the Regional Boards as considered suitable, or potentially suitable, for municipal or domestic water , with the exception that groundwater designated previously designated as unsuitable may retain that designation under certain conditions (SWRCB Res.No. 88-63 as modified by Res No. 2006-0008)

[4]An underground source of drinking water (USDW) is defined as groundwater with TDS less than 10,000 mg L^{-1} in an aquifer with sufficient permeability and of sufficient volume to supply a public water system. Such water must be protected unless otherwise exempted (40 CFR § 144)

The California State Water Resources Control Board (SWRCB) operates a groundwater quality and water level portal named the GeoTracker GAMA Information System ("GAMA," which stands for Groundwater Ambient Monitoring & Assessment; data portal available at http://www.waterboards.ca.gov/gama/geotracker_gama.shtml) (SWRCB, 2014a). This portal provides access to data extending back several decades.

We conducted an analysis of water quality near oil and gas operations in California, based on the minimum concentrations of TDS reported in the GAMA database. All the TDS data available from GAMA on October 10, 2014, were downloaded. The minimum value was determined in each 5 km by 5 km (3 mi by 3 mi) square area with groundwater wells in sedimentary basins with wells associated with oil and gas production starting operation from 2002 through late 2013. Figure 2.7-1 shows the results for southern California binned by the TDS thresholds shown in Table 2.7-1. None of the areas with a TDS value

has a minimum greater than 10,000 mg L^{-1}, and few have a minimum greater than 3,000 mg L^{-1}. This is likely because groundwater of this quality is of limited use, and so groundwater wells would not tend to exist in these areas.

In general, the minimum TDS is below 500 mg L^{-1} in any area where a result is available (Figure 2.7-1). This is true even in many areas along the west side of the San Joaquin Valley, where Bertoldi et al. (1991) mapped the TDS as greater than 1,500 mg L^{-1}. Groundwater with less than 500 mg L^{-1} TDS occurred in many of the oil fields in this portion of the basin (Figure 2.7-1).

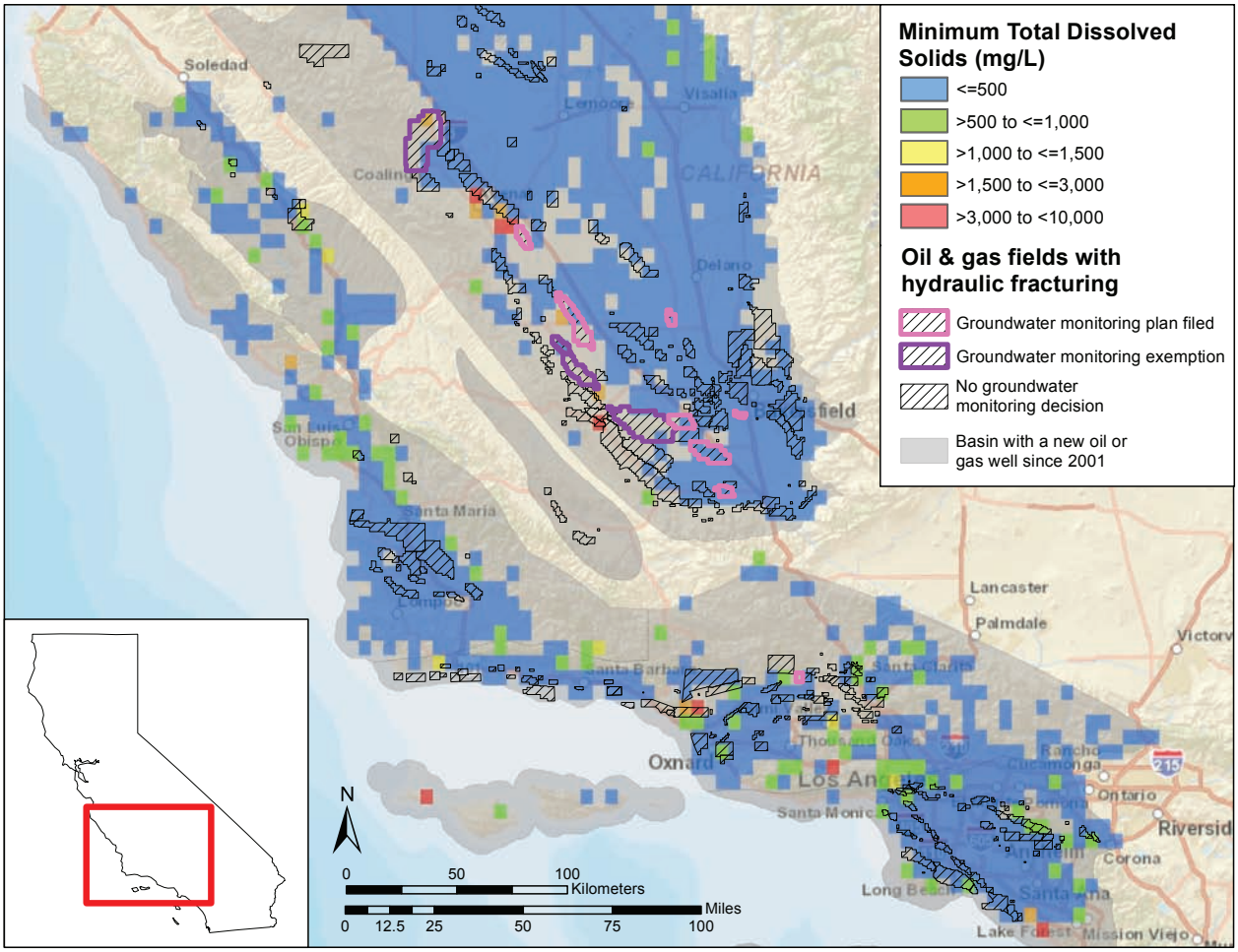


Figure 2.7-1. Minimum total dissolved solids concentration from GAMA in 5 by 5 kilometer (3 by 3 mile) square areas in central and southern California geologic basins with oil production. The status of groundwater monitoring for well stimulation projects is indicated for each field in which they have been filed.

SB 4 exempts groundwater with greater than 10,000 mg L^{-1} TDS from the monitoring requirement, as well as groundwater exempted pursuant to Section 146.4 of Title 40 of the Code of Federal Regulations. The alternative criteria described there include groundwater that occurs with hydrocarbon resources that can be economically produced, as well as groundwater that can be demonstrated to be uneconomical for use. As of October 10, 2014, operators had in some cases applied for and been granted groundwater monitoring exemptions under the TDS and hydrocarbon resource exemption provisions.

The fields for which the SWRCB has approved a groundwater monitoring plan or a groundwater monitoring exemption, according to files posted by DOGGR as of October 10, 2014, are shown in Figure 2.7-1. For the projects that were granted exclusions for groundwater monitoring from the SWRCB, the TDS data available from GAMA were either limited or indicated that the minimum TDS was greater than 1,500 mg L^{-1} (Figure 2.7-1). A possible exception is the North Belridge field.

Figure 2.7-2 shows the locations of unlined percolation pits in the Central Valley and along the Central Coast. According to this figure, percolation pits are active in areas overlying protected groundwater aquifers, especially along the eastern side of the San Joaquin Valley. In some cases, TDS levels are less than 500 mg L^{-1}. It is important to note that groundwater quality beneath the majority of active disposal pits, especially along the West San Joaquin Valley, is not known.

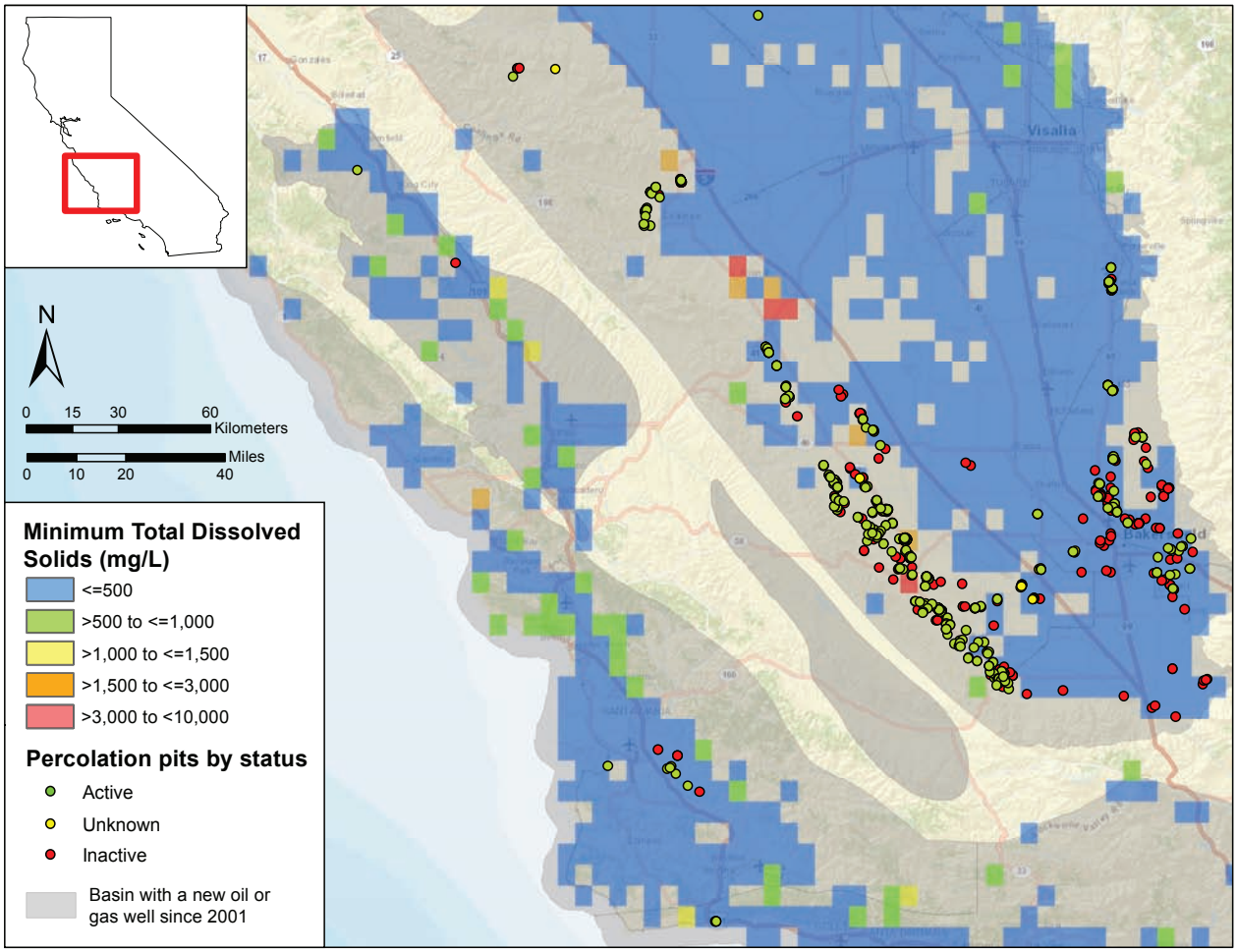


Figure 2.7-2. Minimum total dissolved solids concentration from GAMA in 5 by 5 kilometer (3 by 3 mile) square areas in central and southern California geologic basins with oil production. The location and status of unlined percolation pits in the Central Valley and Central Coast used for produced water disposal is shown. Many unlined pits are located in regions that have potentially protected groundwater.

Figure 2.7-3 provides information about the depth of hydraulic fracturing in each field. Comparison of Figures 2.7-1 and 2.7-2 indicates at least one field, Lost Hills, with hydraulic fracturing of shallow wells (<300 m [1,000 ft] deep) and groundwater of sufficient quality to require monitoring. The minimum depth of fracturing from completion reports discussed in Section 2.6 further supports this. The distribution of minimum fracturing depths indicates most are shallow, and the dataset includes reports of shallow fracturing from fields where groundwater monitoring has been required, indicating protected groundwater is present. The existence of shallow fracturing operations in areas with protected groundwater elevates concern for the hazard of subsurface migration of fluids into groundwater as a result of hydraulic fracturing.

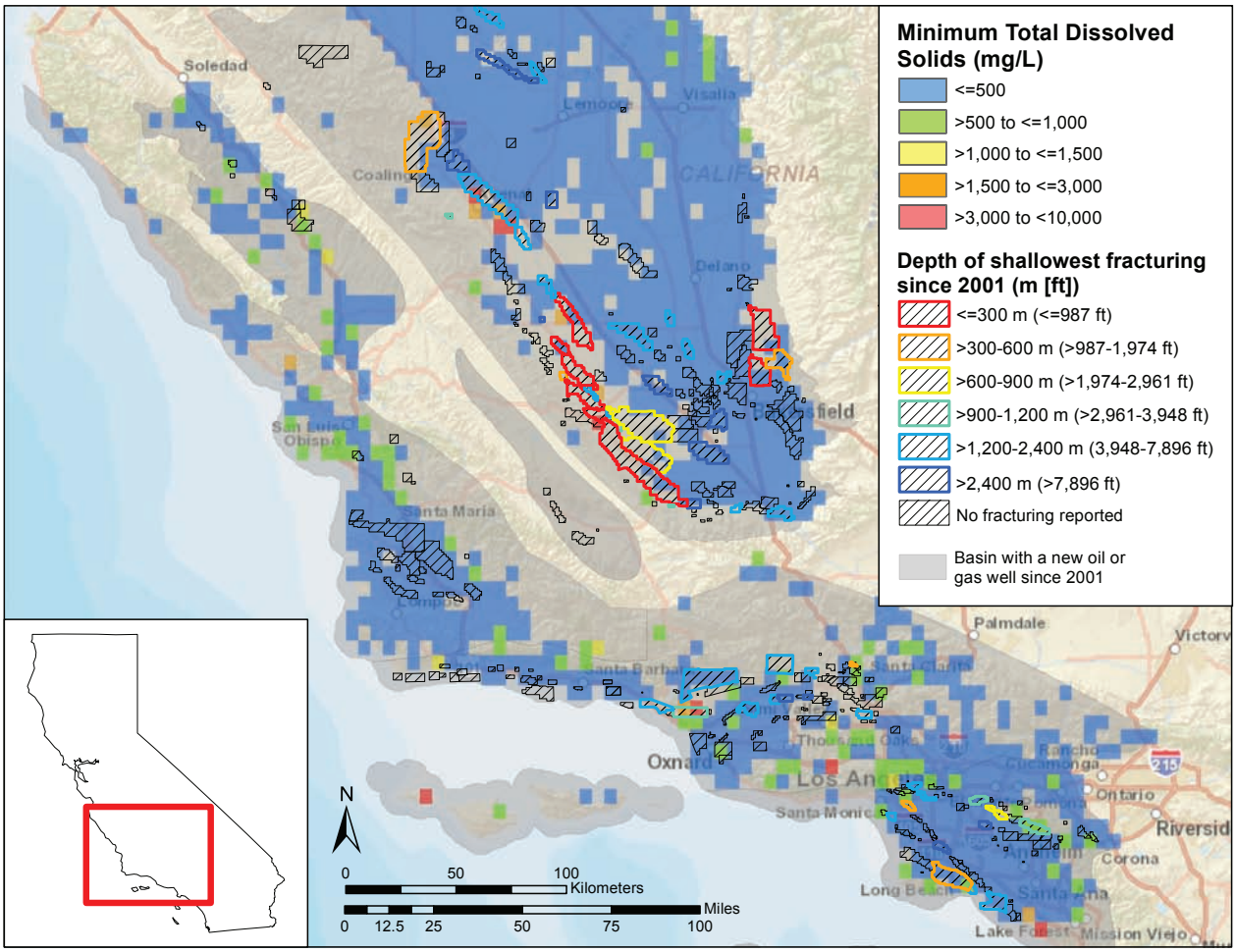


Figure 2.7-3. Minimum total dissolved solids concentration from GAMA in 5 by 5 kilometer (3 by 3 mile) square areas in central and southern California geologic basins with oil production. The available minimum depth of hydraulic fracturing in each field available in Appendix M to Volume I is shown. For most fields, this is the depth of a well in which hydraulic fracturing occurred, so the upper limit of the hydraulic fracture may be in a shallower category. Figure 3-15 of Volume I indicates the type of depth information plotted for each field.

2.8. Alternative Practices and Best Practices

In previous sections, we have examined (1) water use and sources for well stimulation; (2) the known and unknown environmental properties of various chemicals and substances used for well stimulation; (3) the quantities and characteristics of wastewater generated from stimulated wells; (4) the potential surface and subsurface release mechanisms and transport pathways associated with well stimulation; and (5) evidence of possible surface and groundwater contamination from sampling studies conducted near stimulation operations in California and elsewhere. In this section, we describe alternative and best practices that could minimize use of freshwater resources and reduce the risk of water contamination.

2.8.1. Best Practices for Well Drilling, Construction, Stimulation, and Monitoring Methods

Application of good practices while conducting well stimulation can reduce impacts from injected or mobilized fluids. Environmental impacts can be related to surface activities as well as the subsurface aspects of well stimulation. One important concern is the potential loss of containment of subsurface fluids that could result in the contamination of groundwater. Loss of containment is a significant concern for hydraulic fracturing since it is performed at high pressures. Lower-pressure injections (below fracture pressure) of acid for matrix acidizing are less likely to result in loss of containment.

Fracturing in shallower reservoirs has greater potential to result in fractures that have sufficient length to cause loss of containment and possibly impact usable groundwater. The principal way to avoid loss of containment is careful, site-specific characterization of the geologic environment, including determination of the hydrological and geomechanical properties of all stratigraphic layers. This information is then used to develop fracturing models to predict the extent of hydraulic fracturing. The model can then be used to design the injection fluid types, volumes, and rate of injection that should result in fracturing that remains contained within the target reservoir. It should be noted that current industry-standard fracture modeling typically assumes simple bi-wing fracture geometry that is most realistic for gelled fracture treatments (Cipolla et al., 2010; Weng et al., 2011). Tools to model complex fracture geometries (typical of slickwater hydraulic fracturing treatments in very low permeability systems) are relatively less mature (Weng et al., 2011). Traditional bi-wing fracture geometry models tend to overestimate the fracture penetration distance into the reservoir if complex fracture patterns are generated (Smart et al., 2014).

Analysis discussed above has shown that induced fractures that connect with high-permeability structures, such as adjacent wells, are a potential pathway for the contamination of groundwater or the ground surface. Clearly, to avoid problems with leakage along these types of structures, careful characterization of the system is necessary to identify any wells or geologic features within the area expected to be affected by the well stimulation treatment (Shultz et al., 2014). Bachu and Valencia (2014) recommend conducting hydraulic fracturing from offset wells at a safe distance, which is not specified, but would need to be evaluated using fracture modeling and field experience.

Leakage along the well receiving the well stimulation treatment could cause a loss of containment. This is an issue of proper well construction and testing, discussed in detail in Appendix 2.D and reviewed here. The key issue is the isolation of fluid movement up (or down) the well inside the casing, or tubing internal to the casing. Fluid movement along the outside of the casing or fluid exchange between inside and outside the casing, except in zones where such exchange is intended, should be prevented by the casing and cement that bonds the casing to the formation. This aspect of well construction is termed zonal isolation. Factors to be considered as part of well drilling and well construction that are important for achieving zonal isolation are discussed in Appendix 2.D and are available in

technical documents describing accepted industry practices (e.g., API, 2010; ISO 10426 standards) and other technical literature (e.g., Aldred et al., 1999; Cook et al., 2012; Khodja et al., 2010; Lal, 1999; McLellan, 1996). Both internal and external well integrity tests can be performed to check on the integrity of the well and the quality of the zonal isolation.

Hydraulic fracturing treatments are routinely monitored through the pressure and flow rates of injected fluids. These monitoring tools can be used to help prevent loss of containment or identify if treatments remain within the targeted formation. Monitoring the pressure and flow rates into the well are fundamental response parameters that can be used to determine if the hydraulic fracturing treatment is proceeding properly. Both the pressure of the injection fluids and the casing pressure between the production casing and intermediate casing should be monitored. The fluid-injection pressure profile should be compared with the expected pressure profile basing on modeling. If significant deviations from the expected pressure profile are found, the hydraulic fracturing operation should be halted, to gather more information about the system and revisit the fracturing model. For instance, an unexpected drop in pressure could indicate a leak of the fracturing fluids through the casing outside the target formation. Similarly, if pressure builds in the casing annulus, treatment should be halted. This indicates flow behind the production casing, either from the targeted formation, from casing leaks above this zone, or directly from overlying formations into the annulus.

Monitoring can also be performed using geophysical measurements of microseismic (acoustic) signals from the fracturing process and from volumetric responses (dilation or compaction) that occur in response to the fracturing treatment. Such monitoring activities are typically used when new techniques or production areas are being evaluated for development, or if models of hydraulic fracturing require more detailed input (API, 2009), but they are not routine measurements. This type of monitoring provides the most detailed map of the locations where fractures generated of any monitoring method. It is performed using microseismic receiver arrays to detect the very small microseisms (or earthquakes) generated by the fracturing process (Warpinski et al., 2009). Such arrays can be placed in a monitoring hole nearby, in the well being fractured, on the ground surface, or buried in the shallow surface (Gilleland, 2011). The measurement is improved when conducted downhole, closer to where fracturing is taking place. This can be used as an after-the-fact assessment of where fractures were generated, but can also be used interactively, where real-time fracture mapping provides information to adjust the hydraulic fracturing treatment as it proceeds (Burch et al., 2009).

Another geophysical measurement device that can assess the extent of fracture growth is called a tiltmeter. This measurement detects the deformation of the earth associated with fracturing, which can then be interpreted in terms of the fracture orientation and geometry (Cipolla and Wright, 2000). Tiltmeters can be deployed in shallow boreholes or in deeper boreholes and, as for microseismic monitoring, better measurements can be obtained when the device is closer to where fracturing is taking place. Tiltmeters

and microseismic monitoring have some different sensitivities in terms of the types of geometry that can be deduced from the measurements (Cipolla and Wright, 2000). Tiltmeters have also been used in a real-time mode to help guide fracture treatments as they proceed (Lecampion et al., 2004).

Monitoring of wells continues in the post-treatment period to ensure that well integrity is not compromised during production. A principal method is the monitoring of casing pressure (API, 2009). A common indication of a problem is excess pressure in casing annular spaces, which can be accompanied by a buildup of gas. The gas composition can be analyzed to help identify the source of the leak. Casing pressure limits should be established. Guidelines are provided in API RP 90, *Recommended Practice 90, Annular Casing Pressure Management for Offshore Wells*, which can also be used for onshore wells. Other methods to monitor well integrity include conducting a casing inspection log and inspection of tubulars for corrosion.

2.8.2. Best and Alternative Practices for Well Stimulation Fluids

2.8.2.1. Reuse Produced Water for Well Stimulation

Produced water from oil fields is often pumped back into the oil-bearing formation to enhance oil recovery, maintain reservoir pressure, and mitigate subsidence. In California, produced water that is not reused for enhanced oil recovery is sometimes used for other purposes, such as for cooling or agricultural purposes, typically after treatment. However, reuse of produced water for well stimulation treatments is not routine. Well completion reports filed through mid-December, 2014, indicate that there were only 43 documented instances of oil and gas operators using produced water for well stimulation in California, accounting for about 13% of the water used for well stimulation in 2014. Produced water reuse for well stimulation has been shown to be feasible (e. g. Huang et al., 2005) and is becoming more common across the United States. For example, recycling of wastewater for well stimulation has increased in the Marcellus Shale region: prior to 2011, 13% of wastewater was recycled, and by 2011, 56% of wastewater was recycled (Lutz et al., 2013). Reuse for well stimulation is occurring in Texas, New Mexico, and elsewhere. Given constraints on water supplies and concerns about the adequacy of produced water disposal methods, reuse of oil and gas wastewater for subsequent well stimulation may be an attractive option for operators in California.

Reusing oil and gas wastewater for well stimulation has benefits but also some limitations. Reuse as stimulation base fluid reduces reliance on freshwater supplies and provides a disposal option. Additionally, reuse of wastewater for well stimulation can reduce transportation costs, which can be high if freshwater and/or wastewater must be trucked to and from the site, respectively. An advantage of reusing wastewater for well stimulation is that it does not need to be treated as stringently as if it were to be released into the environment (King, 2012). One of the main challenges with reusing produced water is that there are high concentrations of salts, measured as TDS. Base fluids with elevated

levels of TDS can be problematic, because the salts may precipitate in the formation, blocking fractures and reducing formation permeability (Guerra et al., 2011). Removal of TDS typically requires desalination, which often entails extensive pre-treatment to remove organic chemicals that interfere with desalination (e.g., causing biofouling of membrane surfaces). A bench-scale test in New Mexico, however, demonstrated that high-TDS water can be used as a base fluid for cross-linked gel-based hydraulic fracturing fluids (Lebas et al., 2013), eliminating the costly use of RO.

2.8.2.2. Use Alternative Water Supplies for Stimulation Fluids

While most oil and gas operators use freshwater as a base fluid for well stimulation, operators can employ other water sources, such as brackish water or treated municipal wastewater. These alternative water supplies can reduce the use of limited freshwater resources for oil and gas production. For example, Nicot et al. (2012) reports that brackish water accounts for about 20% of water use in the Eagle Ford Shale and 30% of water use in the Anadarko Basin.[12] There are a few documented cases where recycled water from other municipal or industrial users was used as the base fluid for hydraulic fracturing. Operators in the Haynesville Shale gas play in Louisiana, for example, have used treated wastewater from a nearby paper mill (Nicot et al., 2011). A 2012 analysis found that about 30 municipal and industrial facilities provide water to the oil and gas industry in Texas (Nicot et al., 2012).

Use of alternative water supplies can pose a unique set of risks. First, in water-scarce regions with limited freshwater supplies, use of brackish water may compete with more conventional users who may tap this resource and treat it or blend it for municipal or industrial use (Nicot et al., 2012). Second, in areas where the brackish groundwater aquifer is connected to freshwater aquifers, withdrawing brackish groundwater could compromise the quality and availability of water in the freshwater aquifer (Freyman, 2014). An additional risk associated with the use of brackish water is during its transportation and storage, where a spill of this water could have an adverse impact on the local environment. Challenges with using non-oilfield wastewater include guaranteeing a consistent quality of water and the cost of transporting these waters to the well site. Additional research and analysis is needed to determine whether alternative supplies are available for use in stimulation fluids, and whether the use of these supplies poses any concerns for nearby users, including municipalities, industry, and farmers.

12. Brackish water is generally defined as having a salinity greater than freshwater (TDS <1,000 mg L^{-1}) but less than saline or seawater (~35,000 mg L^{-1}) (USGS, 2014a; NGWA, 2010).

2.8.2.3. Apply Principals of Green Chemistry to Chemical Additives used in Stimulation Fluids

Currently, a large number of chemicals are used in well stimulation that have poor or unknown environmental profiles (Section 2.4). There are few controls on what chemicals are being used in hydraulic fracturing, and some chemicals currently being used are toxic, potentially persistent in the environment, or may degrade to toxic or otherwise environmentally harmful products. Properties such as endocrine effects and carcinogenesis, which complete an environmental profile, are unknown for many chemicals listed in Table 2.A-1.

There are many opportunities to apply green chemistry principles to well stimulation formulations and thereby mitigate many of the potential direct impacts of hydraulic fracturing. The principals of green chemistry include developing industrial processes that use chemicals with the best environmental and health profiles, in other words, industrial processes that use chemicals that are non-toxic, do not have other negative or harmful hazardous properties, do not persist in the environment, and do not degrade to undesirable products (U.S. EPA 2011). Some toxic chemical additives that are used in well stimulation could potentially be replaced by non-toxic alternatives. Ideally, the most toxic and/or persistent chemicals could be replaced first. Determination of alternatives for toxic stimulation chemicals would be beneficial, but there currently is very little incentive for oil and gas producers to employ less toxic additive or to invest in research and development of alternatives.

The sheer number of chemicals used makes a full hazard and risk analysis difficult, if not impossible, due in part to the complexity of understanding interactions between chemicals in combination. Reducing the number of chemicals applied would make it easier to evaluate hydraulic fracturing mixtures, insure public safety, and resolve public concerns. Limiting the number of chemicals that can be used in hydraulic fracturing and acid treatments will also assist and simplify regulation. For example, we identified over 60 different surfactants listed in Table 2.A-1, and it may be possible to limit the number of different surfactants being used without compromising effectiveness. Currently, there is no regulatory incentive for oil and gas producers to minimize the number of chemicals used in well stimulation. However, the American Chemical Society (ACS), in partnership with industry and government representatives, has implemented a Green Chemistry Institute, which aims to address issues of pollution prevention and sustainability in chemical use. More sustainable stimulation chemicals could be pursued within this framework.

Characterization of chemicals—including information on toxicity and environmental persistence—is not required prior to use of these chemicals for well stimulation in California. In some cases, data are missing that are needed in the event of an emergency. Recent events associated with the energy industry have underscored some of the risks of a lack of readily (and publicly available) information on chemicals. For example, emergency response to the release of 4-methylcyclohexanemethanol into the Elk River in

West Virginia was hampered by the absence of basic physical, chemical, and toxicological information on that chemical. In the absence of a complete environmental and health profile on a chemical, implementation of a timely and appropriate response by regulatory agencies following releases of these chemicals into the environment is impeded.

The North Sea compact/OSPAR Convention is a good model for how oil and gas production can be done with an eye towards environmental sustainability. In the compact, it is agreed that chemicals will be tested before they are used in the North Sea. The chemicals must pass certain criteria before they are used, and standards for environmental persistence and acute toxicity must be met (OSPAR Commission, 2013). Similar criteria concerning testing for toxicity and environmental persistence are suggested, but not required, in the United States (U.S. EPA, 2011). In another example, Proctor & Gamble established the Environmental Water Quality Laboratory (EWQL), with the mission to measure the toxicity, environmental fate, and physical-chemical properties of chemical ingredients before they were used in their products (http://www.scienceinthebox.com / leadership-in-sustainability-at-pg). These approaches may represent a good model for insuring the safety of unconventional oil and gas development in California.

2.8.2.4. Investigate Application of Waterless Technologies

Companies are developing technologies to reduce or eliminate the amount of water used for well stimulation. Some low-water or waterless stimulation methods have been in use for decades. Alternatives include the use of foams; pressurized gas, such as carbon dioxide or nitrogen; or fluids other than water, such as liquid propane (see e.g., Friehauf and Sharma, 2009; Gupta, 2010; van Hoorebeke et al., 2010). A recent magazine article cites the case of the Marathon Oil Company, which has begun using propane for fracturing in the Eagle Ford Basin in Texas. The company's president stated during testimony to a Congressional committee that the move to waterless fracturing has reduced water consumption by 40 percent in the first 90 days of operations, and as an additional benefit, "The companies are able to resell the propane when it comes up back from the hole" (Wythe, 2013). One industry analyst cautioned, however, that waterless technologies are not poised to have a large effect on water use in the oil and gas industry, barring a major technological breakthrough (Freyman, 2014).

2.8.3. Best and Alternative Practices for Wastewater Characterization and Management

2.8.3.1. Treat and Reuse Oil and Gas Wastewater for Other Beneficial Uses

With proper treatment and monitoring, wastewater generated from oil and gas production—including wastewater generated from stimulated wells—could be used for various beneficial uses. Guerra et al. (2011) identified several beneficial uses currently being practiced in the western United States, including industrial cooling, dust control, irrigation, and water supply to constructed wetlands and wildlife habitats. The advantages of reusing oil and gas wastewater are that the demand for freshwater

resources is reduced, and since water is typically treated to remove contaminants prior to reuse, the risk of water contamination from improper disposal is reduced, and the total volume of wastewater produced is reduced. However, the reuse of produced water that is commingled with returned stimulation fluids raises new concerns, since it is not known how stimulation fluid additives may impact the safety of beneficial reuse. The types and amounts of well stimulation additives found in these waters is unknown, so it is not certain what treatment methods are adequate to allow reuse. Additionally, potentially hazardous chemicals resulting from degradation of the added chemicals and the interaction of the stimulation fluid with the formation need to be carefully evaluated.

Proper treatment is required to ensure that well stimulation chemicals are removed from wastewater prior to reuse. In Section 2.5, we evaluated whether various chemical, physical, and biological treatment technologies commonly used on produced water in California and elsewhere will be effective in removing well stimulation chemicals. Results of this analysis indicate that there is no single treatment technology that can independently treat all categories of well stimulation fluid additives (also see Appendix 2.C). Adequate treatment would require the use of multiple technologies in treatment trains to satisfy effluent requirements. Treatment trains that provide only the most basic treatment, e.g., air stripping/gas flotation followed by filtration, will be ineffective at removing most well stimulation chemicals. Treatment trains utilizing RO are expected to provide the highest level of treatment, due to the effectiveness of RO at removing small (0.001-0.0001 μm) constituents and the need for multiple pretreatment steps to prevent membrane fouling. However, the high cost and energy requirements of RO systems may reduce the economic viability of treating well stimulation chemicals.

2.8.3.2. Characterize and Monitor Produced Water and Other Wastewaters

More extensive characterization of the compositions of wastewater generated by stimulated wells in California is needed. Additional testing needs to be done for wastewater that is not being disposed into injection wells, especially to see if wastewater that is being reused for irrigation, disposed into sewers or unlined pits have been effectively treated. Wastewater compositions should be analyzed at several time points to be able to identify the patterns for how they evolve over time, and to identify when returned stimulation fluids are present in the wastewater. Analytes should include surfactants, solvents, biocides, and other compounds used in hydraulic fracturing fluids. Other analytes to be measured should include general water quality parameters (such as pH, temperature, chemical oxygen demand, organic carbon etc.), major and minor cations and anions, metals and trace elements, BTEX, gases (methane and H_2S) and NORM. The list of analytes needs to be periodically updated to reflect current scientific research, as well as understanding of the wastewater composition patterns in California oil and gas fields where stimulation is occurring.

2.8.3.3. Improve Management Practices for Oil and Gas Wastewater

Disposal of wastewater from oil and gas production occurs by Class II disposal wells, discharge into sanitary sewers, percolation in unlined pits, and treatment for reuse. Evaporation-percolation in unlined surface impoundments (percolation pits) is a practice that intentionally introduces wastewater and its constituents into near-surface groundwater aquifers. The U.S. Department of Energy recommends that "all evaporation pits should be lined … to prevent downward migration of fluids" (U.S. DOE et al., 2009). Texas and Ohio have restricted or stopped the use of unlined pits and percolation basins as a disposal practice for produced water, due to documented groundwater contamination incidents (Kell, 2011). Given the concerns regarding disposal in percolation pits, injection into properly located, constructed, and permitted Class II wells for EOR or disposal would be a better practice (Kell, 2011; U.S. DOE et al., 2009). The reuse of wastewater should be encouraged, but reuse of water from stimulated wells will require adequate safeguards, including monitoring for appropriate chemical contaminants and applying multi-stage treatment systems before reuse (e.g., Liske and Leong, 2006; Appendix C).

When oil and gas wastewater is discharged into sanitary sewers, the wastewater is conveyed to domestic wastewater treatment plants that were not necessarily designed to remove all of the constituents found in oil and gas wastewater from stimulated wells. Although the discharges into the sanitary sewer must be compliant with local pre-treatment ordinances, it is not clear that these requirements are sufficient to address well stimulation chemicals.

The environmental impacts of discharging oil and gas wastewater into Class II wells in California are not entirely understood. There are federal and state requirements for construction and placement of Class II injection wells (Veil et al., 2004), but there are concerns that Class II wells in California may be contaminating protected groundwater. Site characterization requirements include a confining zone free of known open faults or fractures that separates the injection zone from underground sources of drinking water, and construction requirements to ensure mechanical integrity of the well (40 CFR 146.22). There are also operating requirements that limit injection pressure and monitoring and reporting requirements (40 CFR 146.23). A recent detailed review of California requirements for Class II injection wells suggested that current rules may not be adequate for protection of all beneficial uses of groundwater (Walker, 2011). In addition, EPA is expected to release (in 2015) recommendations for best practices for limiting induced seismicity associated with wastewater injection by the oil and gas industry (Folger and Tiemann, 2014). An alternative practice would be to determine the location of protected groundwater in the state, to investigate and review current practices to resolve outstanding issues concerning the use of Class II wells for disposal in California, and to conduct site-specific studies to ensure the safety of proposed disposal methods.

2.8.4. Best and Alternative Practices for Monitoring for Groundwater Contamination

Groundwater contamination can be difficult to detect. Comprehensive baseline and monitoring measurements collected before and after drilling, including regional characterization of background concentrations of groundwater constituents, are necessary to determine impacts on groundwater quality from well stimulation or any other oil and gas development activity.

Baseline data on groundwater quality have not been collected at appropriate locations and in a systematic manner to allow the impacts of oil and gas development on groundwater resources in California to be determined. Improved collection and organization of groundwater data would be a better practice. Some information on background levels of many inorganic and organic constituents, including TDS, trace metals, and VOCs in California, is available from the USGS Groundwater Ambient Monitoring and Assessment (GAMA) program (USGS, 2013). These data should be fully analyzed in future investigations of the impact of well stimulation on groundwater quality in California. However, the GAMA program has objectives related to monitoring drinking water and does not currently collect data in many regions of the state with active oil and gas development (Figure 2.7-1). Investigations of regional and site-specific groundwater impacts from unconventional oil and gas development should be directed at determining the importance of specific contamination pathways, and the extent of groundwater contamination. Developing specific programs examining groundwater impacts of oil and gas development would be a better practice.

In other parts of the country, studies have shown that measurements of methane in groundwater and elsewhere can be an important indicator of leakage from well bores and other sources, such as fractures. Methane levels over 45 mg L^{-1} (ppm) have been observed in New York, West Virginia, and Pennsylvania groundwater (Vidic et al., 2013). Best practice for the development of a comprehensive groundwater monitoring program includes coordinated examination of the concentrations and isotope characteristics of methane.

The State Water Resources Control Board (SWRCB) is issuing groundwater monitoring regulations, due to take effect on July, 2015. The groundwater monitoring regulations being developed by the SWRCB will include both a monitoring plan for areas where oil and gas well stimulation are being conducted, as well as a regional monitoring plan. The SWRCB released its draft model criteria for area-specific groundwater monitoring on April 29, 2015 (SWRCB, 2015), which outlines the design for groundwater monitoring, including collection of baseline data, as well as sampling and testing requirements. These monitoring requirements are expected to develop baseline water quality information and improve the current understanding of water quality impacts of both conventional and unconventional oil and gas development.

2.9. Data Gaps

Numerous data gaps were identified during the course of this investigation that can and should be addressed in order to provide a better understanding of unconventional oil and gas development in California, and associated impacts on water and the environment. Overall uncertainty in our analysis was increased by reliance on voluntary reporting, poor data quality, and missing or inaccurate information in state agency datasets. New regulations, put in place under SB 4, are mandating reporting of more information, but an evaluation of the completeness and accuracy of reporting, as well as the relevance and appropriateness of information being reported, needs to occur in the future as part of the ongoing efforts to fully understand the actual and potential environmental impacts of unconventional oil and gas development. Data that are complete and accurate also need to be submitted and published in a timely manner. Scientists and regulators need to be engaged in an ongoing effort of data analysis and interpretation of information, to arrive at a better understanding of the environmental impacts of well stimulation in California. Below, we identify some of the most critical data gaps identified in our investigation of water impacts of well stimulation.

2.9.1. Reports and Data Submissions Have Errors, Missing Entries, and Inconsistencies

Mandatory and voluntary reporting requires data entry by operators and other responsible parties. It was apparent during our investigations that information submitted to the state was not subject to systematic quality checks or verified, and, as a result, datasets resulting from these submissions contained errors and inconsistencies. Due to data entry errors and inconsistencies, data sets required extensive editing and organization before they could be analyzed. Analysis of uncorrected data can and will result in significant errors in interpretation (e.g., chemical function is routinely reported incorrectly, counts on the number of chemicals may be exaggerated, etc.). Maintaining standardized and verified data, ideally in electronic format, would allow rapid and accurate analysis of oil field activities on a near real-time basis.

In many cases, the data collected by DOGGR and other government agencies contained simple typos and other obvious mistakes. In other cases, information is missing or meaningless. For example, DOGGR's Production and Injection database contained records for active production wells where the number of production days was zero and the information on the type of produced water generated was missing or identified as "other" or "unknown."

Reporting units and other formats differ between important databases (e.g., FracFocus, SCAQMD, DOGGR), complicating comparative analysis and making data integration more difficult and prone to error. In the SCQAMD reports, units for reporting mass compositions of fluids were non-standard and resulted in predictable data entry errors. The SCQAMD data entry requirements are different from both FracFocus and DOGGR records, and basic

information such as CASRN and API well number are entered in different formats or not at all. FracFocus is not linked or standardized to other information, such as well production information, collected by DOGGR and other agencies.

Implementation of a quality assurance program and standardization would improve the quality of the data and allow ongoing analysis by agencies compiling the data. For example, in the completion reports submitted to DOGGR, it could be required that the percentage of various chemicals reported as added to each operation must always add up to 100% (± 5%). In other cases, simple controls, such as checking that entries match an appropriate range of possible values, would results in marked improvements in data quality. The use of entries such as "other" or "unknown" should not be acceptable for critical parameters or values.

The DOGGR GIS wells file has missing data for many data entry fields, which are needed for assessment of impacts. For example, as of November 2014, only 20% of records have values filled in for well depth. There are also incorrect data for some values; for example, there are some wells that have a latitude or longitude value of zero.

There are also some files where the data is poorly organized, making analysis cumbersome. For example, in the new completion reports, the "Location of Treatment" sheet does not have the actual location of where the stimulation was conducted (such as fields for latitude, longitude, field, area, or county). Instead, this information is located in a different sheet in the file that is intended to list all the chemicals used in each treatment. DOGGR and other agencies should consider normalizing data spreadsheets, and preferably storing the data in an accessible database.

2.9.2. Information is Not Easily Accessible to the Public

Agencies responsible for collecting information do not always make the information easily accessible to the public, limiting the use of these records to inform citizens and policymakers. The use of the industry website FracFocus is a reasonable model for inputting chemical data, but extracting data is difficult, and accessibility to electronic datasets or databases is limited and not freely available to the public. Information on water quality and the location of groundwater extraction wells in GAMA is not reported with appropriate or accurate location information (latitude and longitude or Universal Transverse Mercator [UTM] coordinates) to allow open and public risk analysis. Additionally, lack of publication of well locations hinders the development and public evaluation of monitoring plans that must be submitted under new regulations.

2.9.4. Information is Submitted in Inadequate Data Formats

In many cases, data needed for analysis are only available as PDF documents or displayed on web pages, rather than available in well-organized electronic data structures. The nontransferable nature of the datasets makes data entry and analysis burdensome and

time-consuming, as records need to be retyped or extracted from PDF documents. The use of non-standard data formats and the lack of a well-designed database system may have also resulted in a decreased ability to detect errors in data submission, resulting in incorrect entries, typos, and duplicate records. The use of PDF formats for data reporting is an important problem for reporting all types of data.

2.9.4. Poor Collaboration Between State and Federal Data Collection Efforts

In collecting information for this project, we found that datasets collected by different agencies were frequently contradictory, lacked standardization between datasets (e.g., reporting units differed, etc.) and difficult to harmonize. There are currently separate initiatives by the Central Valley Regional Water Quality Control Board, the South Coast Air Quality Management District, DOGGR, and other agencies to collect information, with each agency having its own purposes. The lack of collaboration and standardization between agencies resulted in duplicated efforts.

In many cases, stimulation events were described differently in different databases. For example, we found data for the same well stimulation operation that was reported in FracFocus, in DOGGR completion reports, and in data submitted to the SCAQMD, but these sources sometimes reported different dates, water volumes, and other information that made comparison or integration of information from different sources difficult. Coordinated integration of data collection, standardization of reporting units, and consistent unique identifiers for authorized treatments would require a new level of interdepartmental coordination and cooperation, but would allow improved regulatory oversight. The unique API well numbers should be included with all reports, data, and other documents concerning activities associated with wells or groups of wells (e.g., wastewater management activities).

2.9.5. Chemical Information Submitted by Operators is Incomplete or Erroneous

Chemical data submitted by operators includes errors and omissions. The product CASRN and chemical name are not always included for each chemical reported. Frequently, the chemical purpose is incorrect or missing. Chemicals that are classified as trade secrets, confidential business information, or used in proprietary blends are listed without CASRNs. Products listed without CASRNs cannot be definitively identified by chemical name alone, and thus cannot be adequately evaluated for hazards, fate, and treatment. Even when CASRNs are provided, they are not always correct. For example, chemical CASRNs are sometimes reversed or missing digits altogether (see comments about quality control above). Frequently, the reported chemical purpose includes all possible uses for the chemicals, to the point that the information provided is meaningless. Furthermore, impurities are typically not identified as such, and are instead given the same purpose description as the active ingredient in the chemical product. Hazard and environmental analysis of chemicals used in stimulation fluids is hindered by the lack of quality control and standardization in reported data.

2.9.6. Chemicals Lack Data on Characteristic Properties Needed for Environmental Risk Analysis

Most of the chemicals being used for well stimulation lack publicly available physical, chemical, or toxicological measurements needed for the development of an environmental profile. An environmental profile is needed to provide a complete hazard and risk assessment on a chemical (OECD, 2013; OSPAR, 2013; Stringfellow et al., 2014; U.S. EPA, 2011). At a minimum, the physical, chemical, and biological information needed to develop an environmental profile includes log octanol-water partition coefficients (log K_{ow}), Henry's constants (K_H), soil organic carbon-water partition coefficients (K_{OC}), biodegradability, and acute toxicology. Other information on chronic effects, potential for bioaccumulation, and other properties are also needed. The technical information in an environmental profile is needed for developing environmental fate and transport models, reviewing waste management plans, preparing for spills and accidents, selecting treatment technologies, evaluating reuse projects, and conducting hazard assessments.

Chemical data generated by industrial groups are sometimes contained in material safety data sheets (MSDS); however, these data are not always publicly available and cannot always be confirmed or reviewed. Material safety data sheets cannot be considered reliable sources for chemical, physical, and toxicological data without a public review and validation of the published information.

Publicly available experimental data on the toxicity of many stimulation chemicals to aquatic species, including algae and aquatic animals, and mammalian species are sparse. In particular, aquatic toxicity data are missing testing of native or resident species that are important to California. Measurement or publication of aquatic and mammalian toxicity data is currently not required prior to using chemicals in well stimulation. This lack of available data increases risk to human and environmental health, since the lack of information prevents the ability to make informed decisions and apply an appropriate response during failures and accidents.

In addition to a basic analysis of acute toxicity, data is needed on the potential impacts of chronic exposure to well stimulation fluids in ecological receptors. Measurements of sublethal impacts on plants and animals, such as survival potential and population viability, are not available for most chemicals used in well stimulation. More data is needed on potential sublethal impacts on ecological receptors due to exposures to fluid additives.

The fate and transport of chemical mixtures in the environment is not well understood. Hydraulic fracturing fluids contain complex mixtures, and the interactions of these chemicals in the environment is unknown. For example, easily degradable but toxic components such as methanol are in admixture with biocides, added to prevent biodegradation from occurring. How biocides would influence the persistence of methanol in the environment is unknown, but the methanol might transport further in groundwater in the presence of the biocide, presenting greater risk than methanol alone. Scientific investigation of the environmental fate of chemical mixtures is needed.

2.9.7. Data on Chemical Use from Conventional Oil and Gas Operations are Not Available

Chemical use information for all oil and gas development operations is not available and would be useful for providing context to chemical use during well stimulation. SCAQMD is now collecting data on chemical use during well drilling, installation, and rework in parts of southern California, but similar data are not available for the San Joaquin Valley where the majority of oil and gas extraction takes place. To our knowledge, no data is being collected on chemical use during other oil and gas development activities, such as EOR. Data collected by SCAQMD do not carefully differentiate between well stimulation treatments and other activities, such as well maintenance, making it difficult to interpret and evaluate well stimulation chemical use in the context of overall chemical use. Many of the same chemicals (e.g., biocides, corrosion inhibitors, surfactants, etc.) are used for other oil and gas development activities as are used in production aided by well stimulation. More complete and consistent reporting and tracking of chemical use for all oil and gas development activities will allow a better understanding of the impacts of well stimulation in the context of overall oil and gas development.

2.9.8. Lack of Data Regarding the Chemical Composition of Produced Water from Stimulated Wells

There is a lack of information regarding the characteristics of produced water and other wastewater generated from well stimulation in California. Produced water from stimulated wells will contain chemicals used in hydraulic fracturing, but the amounts of chemicals returning during production and the time period over which they return has not been measured. Data are needed regarding how wastewater constituent concentrations and composition change over time.

Produced waters will contain reaction products from the complex mixtures of chemicals used in hydraulic fracturing. Lack of knowledge concerning the fate of the injected stimulation fluids in the subsurface, and the potential for them to be transformed, or to mobilize formation constituents over the lifetime of production from the well, needs to be determined. The nature of the reaction byproducts, the amounts and types of materials returning to the surface during the lifetime of the well, and hazards associated with these reaction byproducts are entirely unknown and need to be investigated.

Poor understanding of wastewater composition is a major impediment to the safe and beneficial reuse of produced water from stimulated wells. It is unknown how (or if) well stimulation chemicals or their byproducts have been introduced into the environment via disposal or reuse practices, such as percolation or water flooding. California specific investigations of water reuse and disposal practices are needed to fill this data gap.

There are limited data concerning the composition of produced waters from conventional wells, which prevents a comparison between the conventional and unconventional oil

and gas development. Current practice in California mingles the produced waters from stimulated and non-stimulated wells before treatment. If there are differences between wastewater from conventional and stimulated oil and gas operations, the differences would have implications for how each wastewater should be handled, treated, and disposed. Previous studies on the chemical quality of produced waste in California were conducted decades ago, and new studies need to be conducted characterizing produced water and other oil and gas industry wastewaters in California.

Water quality analyses required under new regulation and submitted to DOGGR with well completion reports do not typically measure specific stimulation chemicals, with the exception of a total carbohydrate test for guar. Analysis is not conducted for major well-stimulation-fluid components of concern, such as biocides or surfactants, or potentially harmful reaction products that may form within the formation following introduction of the stimulation fluids. The operators also do not report the exact time at which the recovered fluid sample was collected relative to the stimulation event, so it is difficult to interpret what the samples truly represent.

2.9.9. Incomplete Information Regarding Wastewater Management, Disposal, and Treatment Practices

Data on wastewater disposal and management are incomplete. There is conflicting or inadequate information on current disposal and reuse practices, especially concerning percolation pits and Class II wells. Cradle-to-grave documentation on wastewater management would allow individual sources of wastewater, such as individual wells, to be related to a specific disposal or reuse site, such as a percolation pit.

Systems for documentation of wastewater management practice need modernization, and ambiguous or uninformative entries should not be allowed. For example, the third most common disposal method reported by operators was “other.” DOGGR staff confirmed that some operators are using the “other” category to describe disposal that is, in fact, included in some of the other categories—for example, subsurface injection, discharge to a surface water body, disposal to a sanitary sewer system, etc. (Fields, 2014). Some disposal methods—such as reuse for irrigation or groundwater recharge—are not included as separate categories in the DOGGR production/injection database. During meetings held as part of this study, some operators have suggested that their current practices are not consistent with the data they have reported to DOGGR. Insufficient quality control for operator-submitted data, and inadequate categories for wastewater disposal methods, result in an incomplete picture of current wastewater disposal practices.

There is no central resource for data concerning wastewater treatment practices. In collecting information for this project, data sources for confirmation of common treatment practices varied from NPDES permits and government agency reports, to personal communications, brochures, and factsheets. Due to the lack of a centralized data resource, the frequency of specific wastewater treatment practices and overall trends are unknown.

2.9.10. Incomplete Information on the Impacts of Contamination from Subsurface Pathways

Subsurface pathways and mechanisms are difficult to characterize, and information concerning potential groundwater contamination from hydraulic fracturing is very limited. Peer-reviewed studies investigating the possibility of contaminant transport due to fracturing operations have not been conducted in California. Studies conducted in other areas have suggested contamination is possible or has occurred, but the applicability of those results to California cannot be determined without more investigation, due to the unique conditions existing in California.

2.9.11. Lack of Accurate Information Regarding Old and Abandoned Wells

The extent to which abandoned and deteriorating wells may present a hazard in California needs to be assessed. Documentation of the location, construction, and the method of abandonment for currently unused wells are required before assessment of hazards (or methods for remediation) can be performed. DOGGR has a program that requires operators to conduct regular testing of idle wells to ensure that they are not impacting surface and groundwater, but similar testing is not required for abandoned or buried wells. The datasets regarding idle wells are inconsistent. For example, the DOGGR GIS wells file lists 13,450 wells as idle, but another "Idle Wells" file on the DOGGR website lists a total of 21,347 wells as idle.

2.9.12. Lack of Knowledge about Fracture Properties in California

The process of fracture creation and propagation is currently an area of active research, with the bulk of the work focusing on the properties of gas shales in states other than California. This research applies to deep formations and thus evaluates pathway formation scenarios over large vertical distances. Fracturing has been practiced in California for decades (Walker et al., 2002), but fundamental studies of fracturing behavior, fracture propagation, and the orientation of fractures relative to reservoir depth for California geology are lacking. Fully understanding this behavior is particularly important in California due to the possibility of relatively shallow fracturing depths (200–300 m [650–1,000 ft] from surface) compared to other regions using hydraulic fracturing technology.

Although the reporting of the extent of stimulation geometry has been required for operations occurring after January 1, 2014, the resulting data assessed for this report indicates it generally does not regard the extent of fracturing from single stages, limiting what can be discerned about fracture geometry from these data. Some of the reported data are obviously inaccurate (for example, some of the wellbore end depths are shallower than the corresponding wellbore start depths) or inconsistent with reporting requirements (for example, wellbore start depths are sometimes reported as zero instead of the start of the stimulated interval within the wellbore). Further, if data regarding fracture geometry

were reported, the accuracy of this data would be unknown unless the data supporting the estimates of fracture geometry, and the methods used to analyze the supporting data, were reported by operators.

2.9.13. Incomplete Baseline Data and Monitoring Studies for Surface and Groundwater

Long-term monitoring and studies of surface and groundwater in oil and gas producing regions of California are needed to determine if groundwater resources have been impacted. There is a lack of information on the quality of surface or groundwater near stimulated oil fields, and baseline (or up-gradient) data collection is needed. Significant data gaps exist regarding current knowledge of groundwater quality in California, including the location and extent of protected groundwater that contains less than 10,000 mg L^{-1} TDS. Concentrations of methane, trace metals, NORM, and organic chemicals in groundwater in oil and gas producing regions are unknown, and are needed to assess impacts of unconventional oil and gas development. New regulations implemented under SB 4 and other programs are beginning to address this data gap. The effectiveness of these regulations needs to be evaluated in the future.

2.9.14. Lack of Information on Spills

As discussed above for other types of data, there are numerous inconsistencies between agencies concerning the information collected on spills and accidental releases in California. Databases maintained by OES and DOGGR on surface spills and leaks associated with oil and gas production often do not agree, increasing uncertainty in our understanding of environmental impacts from accidents. Inconsistencies exist concerning the number of spills that have occurred and details regarding those spills. This discrepancy is likely due in part to the fact that OES sends spill reports electronically to DOGGR, and then a subset of the information is entered into DOGGR's database. Although OES is responsible for collecting spill information and submitting it to the appropriate agencies, there are spills in DOGGR's database that are not in OES's. Similarly, there are oil and produced water spills in the OES database that are not in the DOGGR database. DOGGR often coordinates with operators after spills—especially for large spills or when spills impact waterways—but there is no mechanism for conveying this information back to OES. Operators often submit corrections to OES after a spill takes place, and these corrections are not always entered into either DOGGR's database or the OES database that is available online. Another major concern is that DOGGR only captures information on oil and produced water spills, and therefore does not have record of spills associated with chemicals used for oil and gas production.

2.10. Main Findings

2.10.1. Water Use for Well Stimulation in California

1. We estimate that well stimulation in California uses 850,000 to 1,200,000 m^3 per year (690–980 acre-feet) of water. Our estimate is based on a combination of data sources to provide a best estimate that reflects the uncertainty in both (a) the number of operations that are occurring, and (b) how much water each operation uses on average.

2. Operators obtained the majority of water needed for well stimulation from nearby irrigation districts (68%), produced water (13%), operators' own wells (13%), a nearby municipal water supplier (4%), or a private landowner (1%).

3. Hydraulic fracturing has allowed oil and gas production from some new pools where it was not previously feasible or economical. We estimate that freshwater use for enhanced oil recovery in fields where production is *enabled* by stimulation was 2 million to 14 million m^3 (1,600 to 13,000 acre-feet) in 2013. By comparison, freshwater use for enhanced oil recovery in *all* oil and gas fields was 13 million to 44 million m^3 (11,000 to 36,000 acre-feet) in 2013.

4. Local impacts on water usage appear thus far to be minimal, with well stimulation and hydraulic-fracturing-enabled enhanced oil recovery accounting for less than 0.2% percent of total annual freshwater use within each of the state's planning areas, which range in size from 830 to 19,400 km^2 (320 to 7,500 mi^2). However, well stimulation is concentrated in water-scarce areas of the state, and an increase in water use or drawdown of local aquifers could cause competition with agricultural, municipal, or domestic water users.

2.10.2. Characterization of Well Stimulation Fluids

1. Records describing the chemical composition of hydraulic fracturing fluids between 2011 and 2014 were voluntary, and represent one-third to one-fifth of the total hydraulic fracture treatments thought to have occurred in California during that period.

2. Over 300 different chemicals or chemical mixtures were identified as having been used for hydraulic fracturing in California. Of the disclosed chemicals, approximately one third of the chemical additives lacked a CASRN, and therefore any enumeration of the number of chemicals used in hydraulic fracturing should be considered approximate.

3. Information on chemical use during acid stimulation treatments is very limited. Analysis of regional data and data collected as part of new mandatory reporting requirements in effect since January 2014, identified over 70 individual chemicals or chemical mixtures used during acid treatments, approximately one-third of which were different from chemicals used in hydraulic fracturing.

4. Over 60 chemical additives with a median usage of 200 kg (440 lbs) or more per treatment were found. At least nine of these compounds are proppants, and many are solvents, crosslinkers, gels, and surfactants. Since these compounds were used in significant amounts, they are considered priority compounds for characterization of their hazards and risks.

5. Almost two-thirds of the chemicals reported to be used in hydraulic fracturing or acid treatments did not have publicly available information allowing an assessment of environmental toxicity. Environmental profiles need to be developed for these chemicals.

6. Thirty-three chemicals have a GHS ranking of 1 or 2 for at least one aquatic species, suggesting they could present an environmental hazard if released to surface waters.

7. Significant data gaps exist concerning the hazard, toxicity, and environmental persistence of chemicals used in well stimulation. Additionally, over 100 of the reported materials used for well stimulation are identified by non-specific name and reported as trade secrets, confidential business information, or proprietary information. These materials cannot be evaluated for hazard, risk, and environmental impact without more specific identification.

8. A full understanding of the environmental risk associated with unconventional oil and gas development will require a full disclosure of the chemicals used and better understanding of the environmental profile of each chemical. Environmental profiles include an understanding of a chemical's toxicity, transport properties, and persistence in the environment. A formal environmental review process for all chemicals and chemical mixtures, such as the EPA Design for the Environment program, is recommended.

9. Methods for the detection of chemical additives, their byproducts, and degradation products in environmental samples need to be developed. Many of the chemicals being used do not have standard methods of analysis.

2.10.3. Wastewater Quantification, Characterization, and Management

1. Produced water, recovered fluids, and other wastewaters from stimulated wells will contain chemicals from hydraulic fracturing fluids and their reaction byproducts, but the concentrations of these chemicals in wastewaters will change over time and have not been fully characterized.

2. Produced water, recovered fluids, and other wastewaters from stimulated wells will also contain various other contaminants in dissolved substances from waters naturally present in the target geological formation, substances extracted or mobilized from the target geological formation, and residual oil and gas.

3. During hydraulic fracturing, recovered fluids that are captured before production represent a small fraction of the injected fracturing fluids (~ 5%). In contrast, recovered fluid volumes for acid treatments tend to be a higher percentage of the injected fluid (50–70%), but data on acid fluid recovery is limited and may not be representative.

4. Recovered fluid volumes are a small fraction of wastewater generated within the first month of production. These results indicate that studies from other regions of the country showing significant recovery of "flow-back" fluids have limited application to California.

5. Recovered fluid samples from stimulated wells have been shown to contained high concentrations of salts, trace elements (arsenic, selenium, and barium), naturally occurring radioactive materials, and hydrocarbons. Carbohydrates (gels) were detected in some recovered fluid samples, and this suggests that other stimulation chemicals may also be present. In contrast, produced waters from stimulated wells have not been characterized.

6. Recovered fluids are typically stored in tanks at the well site prior to disposal. According to well completion reports filed and posted through December 2014, more than 99% of recovered fluids are injected into Class II disposal wells. A small amount (less than 0.3%) of the recovered fluids are recycled.

7. The net produced water volumes generated in the first five months of production from stimulated and non-stimulated wells were not substantially different, although their distributions were different. There results suggest there are few differences in the volume of water produced from conventional and unconventional wells, but that some further investigation of these issues could be warranted.

8. There is a lack of information regarding the mass of stimulation fluids recovered after treatment. The concentration of returned stimulation fluids and their reaction byproducts in produced water over time needs to be investigated. The fate of the injected stimulation fluids in the subsurface, and the potential for them to be transformed, or to mobilize formation constituents over the lifetime of the production of the well, needs to be determined.

9. From January 2011 through June 2014, it has been reported that nearly 60% of the produced water from stimulated wells was disposed of by evaporation-percolation in unlined pits. An estimated 36% of the active unlined pits in California are operating without the necessary permits from the Central Valley Regional Board.

10. Subsurface injection in Class II wells, for disposal or enhanced oil recovery, was the second most commonly reported disposition method for stimulated wells in California, accounting for approximately 25% of the produced water from stimulated wells.

11. The impacts on the environment of common disposal practices for produced water that may contain stimulation fluids, including percolation pits and well injection, are poorly understood.

12. Information on current treatment and reuse practices for all wastewater from oil and gas operations in California is limited. Available data suggest that simple treatment technologies (e.g., oil-water separation, water softening, gravity separation, and filtration) are predominantly being used for produced water in California. More complex treatment trains—capable of removing an extensive array of chemicals—are used sporadically.

2.10.4. Contaminant Release Mechanisms, Transport Pathways, and Impacts to Surface and Groundwater Quality

1. Several plausible release mechanisms and transport pathways exist for surface and groundwater contamination associated with onshore well stimulation in California. They are depicted in Figures 2.6-1 and 2.6-2, and summarized in Table 2.6-2.

2. Release mechanisms and transport pathways of high priority for the state are percolation of wastewater from disposal pits; injection of produced water if conducted into protected aquifers; reuse of produced water for irrigation; disposal of produced water into sewer systems; potential leakage through abandoned wells; and potential leakage through fractures.

3. Some of the release mechanisms that were identified are primarily relevant to California, and are uncommon elsewhere, including use of percolation as a disposal method and reuse of produced water for irrigation.

4. Percolation pits provide a direct pathway for the transport of produced water constituents, including returned stimulation fluids, into groundwater.

5. With proper siting, construction, and maintenance, subsurface injection using properly sited Class II wells is less likely to result in groundwater contamination than disposal in unlined surface impoundments.

6. There is growing interest in expanding the beneficial reuse of produced water for agriculture, particularly for irrigation. The use of produced water from unconventional production raises specific or unique concerns. Treatment and reuse of produced water from fields with stimulated wells should include appropriate monitoring and treatment before reuse for irrigated agriculture.

7. According to completion reports, fracturing occurs at shallower depths in California than is typical for other regions of the country. In approximately one-half of the operations, fracturing may extend to depths less than 300 m (1,000 ft) from the surface. The shallow depths of fracturing, combined with the deep groundwater aquifer in the Central Valley, raise concern that fractures may intercept protected groundwater resources. Additional research is needed to determine how often this occurs, if at all, and the consequences if it does occur.

8. Determining where fractures occur is an important component of determining exposure pathways. The reliability of models used by industry to estimate a fracture zone (axial dimensional stimulation area) should be determined.

9. In studies conducted elsewhere, water contamination associated with well stimulation has been documented in some places, but several studies have not found any contamination due to stimulation. No incidents of groundwater contamination due to stimulation have been noted in California to date, although there has been very limited monitoring conducted to detect any water quality impacts.

10. There is a lack of information on the quality of surface or groundwater near stimulated oil fields. Baseline data collection prior to stimulation has not been required in the past. No cases of contamination have yet been reported, but this may be primarily because there has been little to no systematic monitoring of aquifers in the vicinity of oil production sites.

11. Significant data gaps exist regarding current knowledge of groundwater quality in California, including the location and extent of protected groundwater that contains less than 10,000 mg L^{-1} TDS. Concentrations of methane, trace metals, NORM, and organic chemicals in groundwater in oil and gas producing regions are unknown. New regulations implemented under SB 4 and other programs are beginning to address this data gap. The effectiveness of these regulations needs to be evaluated in the future.

2.11. Conclusions

This chapter represents a review and analysis of what is currently known about well stimulation technologies in relation to water resources and the water environment. The quantity of water being used for well stimulation is relatively small and local impacts of water usage appear thus far to be minimal. Well stimulation accounts for less than 0.2% percent of total annual freshwater use within each of the state's planning areas. Water use for well stimulation, however, is occurring in water-scarce regions and, given the critical availability of water in these areas, could reduce the water available for other uses.

A significant analysis included in this chapter is the identification of the chemicals being used in well stimulation in California. An investigation of the properties of these chemicals shows that many of them are poorly characterized for properties important to determining their hazard and potential impact to the environment. A list of priority stimulation chemicals, requiring further review, was developed based on prevalence of use and toxicity. Additionally, it is apparent that many chemicals are being used that cannot be evaluated for their hazards or potential environmental impact.

The chemical characteristics of produced water generated from stimulated wells in California are largely unknown, however it is apparent that produced water from stimulated wells will contain well stimulation chemicals or their reaction by-products. Under SB 4, chemical data are being collected for "recovered fluids," but recovered fluids are not representative of returned injection fluids and other wastewater produced over the life of a well. Time-dependent chemical characterization of produced water from stimulated wells are needed to improve management, treatment, and disposal practices. Additionally, mass balance analyses at individual well sites are warranted to clarify the fate of stimulation chemicals remaining in the formation and the quantities of stimulation chemicals in produced water. Geochemical modeling would complement these efforts to characterize chemical fate and transport for stimulated wells.

In California priority potential environmental release mechanisms include disposal of produced water in unlined pits, injection of produced water into potentially protected groundwater, reuse of produced water for irrigation, and disposal of produced water in sewer systems. Unlike in other parts of the country, contamination of water resources due to spills of well stimulation chemicals have not been documented in California, however spills of produced water have occurred. The transport of contaminants through induced

fractures to groundwater has not been established, but should be evaluated in California, where fracturing depths are much shallower than in other parts of the country. Other potential subsurface release mechanisms include leakage through compromised wells and leakage through natural subsurface fractures, however the importance of these pathways is also unknown.

In California, no incidents of groundwater contamination due to well stimulation have been documented. Historically, baseline data were not collected on groundwater quality prior to initiating well stimulation activities, making it difficult, and in some cases impossible, to attribute possible contamination to nearby stimulation operations. There has not been a coordinated monitoring program for water resources located in the vicinity of oil and gas fields where stimulation is occurring that could detect or identify sources of contamination.

Application of good practices while conducting well stimulation can reduce impacts from injected or mobilized fluids. Practices such as collection of baseline measurements before drilling, proper well construction, and application of green chemistry principles are advisable. Many significant data gaps were identified. Data collection in many cases is not systematic, of high quality, or well organized. Many of the chemicals used in well stimulation have not been properly identified. Wastewater constituents and concentrations are not well understood. Data on the treatment technologies being used at individual well sites are not available. Although it is possible to identify potential chemical release mechanisms and the associated potential contamination pathways, insufficient data exist to confirm or refute concerns that surface and groundwater resources have been or may be contaminated by unconventional oil and gas development.

It is expected that many of data gaps will be addressed under new regulations being promulgated as part of implementation of SB 4 legislation, but there is a clear need for directed scientific studies related to the water environment. These studies are needed to answer important questions concerning the safety and sustainability of unconventional oil and gas development. How green chemistry principals might be applied to hydraulic fracturing requires scientific study. A better understanding of overall wastewater management practices in the industry are needed, including understanding the fate of injected chemicals, the chemical composition of wastewaters over varying time and spatial scales, and a complete understanding of methods and practices of water reuse and disposal. Mass-balance analyses at individual well sites are warranted to clarify the fate of stimulation chemicals remaining in the formation and the quantities of stimulation chemicals in the wastewater. The effects of legacy and current practices on local and regional groundwater quality need priority investigation, and should be complemented with geochemical modeling to characterize the fate and transport of well stimulation chemicals. Coordinated investigations need to be conducted to determine which, if any, of the identified potential pathways pose a significant risk for releasing well stimulation chemicals or other contaminants into the environment.

2.12. References

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Chapter Three

Air Quality Impacts from Well Stimulation

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3.1. Abstract

Well stimulation has the potential to emit greenhouse gases (GHGs), volatile organic compounds (VOCs), nitrous oxides (NO_x), toxic air contaminants (TACs), and particulate matter (PM). These pollutants can have impacts across various temporal and spatial scales ranging from long-term, global impacts (e.g., from GHGs) to local, short-term impacts (e.g., from TACs). Because oil and gas development in general can have these impacts, the purpose of this chapter is to evaluate what is known about the contribution of well stimulation to general impacts from oil and gas development. This chapter performs analysis at the statewide scale (GHGs) and at regional air district levels (criteria pollutants and air toxics). For an analysis of air impacts at small spatial scales, see Volume II, Chapter 6, which covers public health aspects of oil and gas development.

Detailed air pollution inventories are performed by the California Air Resources Board (CARB) for all major industrial sectors, including oil and gas production. Current inventory methods provide estimates of the air quality impacts related to oil and gas activities (see discussion of inventory data gaps below).

Statewide, oil and gas operations are small contributors to GHG emissions (4%), and most of these GHG emissions are associated with heavy oil production in oilfields developed without well stimulation.

In the San Joaquin Valley air district, oil and gas sources are responsible for significant contributions to sulfur oxides (SO_x) emissions (31%) and smaller contributions to reactive organic gases (ROGs) and NO_x (8% and 4%, respectively). Oil and gas activities in the San Joaquin Valley are estimated to contribute to non-negligible (>1%) fractions of some TAC species (benzene, formaldehyde, hexane, zylene) and the majority (70%) of hydrogen sulfide emissions. The fractional importance of upstream oil and gas sources to air quality concerns is higher in some sub-regions within air districts, such as western Kern County. In the South Coast air district, the oil and gas sector is a small source (<1%) of all studied pollutants.

Well stimulation is estimated to facilitate about 20% of California production, and direct well stimulation emissions represent only one source among many in the oil and gas production process. Applying these weighting factors, well stimulation emissions (direct and indirect) can be estimated at approximately one-fifth of emissions reported above.

Experimental studies of air quality in California suggest that current inventory methods underestimate methane and VOC emissions from California oil and gas sources. This suggests that the above inventory results should be considered lower-bound estimates, and the degree of inventory underestimation varies by study type and location.

Oil and gas activities occur in California air basins that already face severe air quality challenges. The two largest oil and gas-producing regions in California are in the San Joaquin and South Coast air basins, which are non-compliant with federal air quality (ozone and PM) regulations. In some cases, this non-compliance is rated as "severe" or "extreme."

While well stimulation emissions are a small portion of overall emissions sources in California, they can still be improved. A significant reduction in emissions related to well stimulation is possible using currently available technology. Some mitigation technologies are currently mandated by federal or state regulatory requirements, such as "green completions" technologies that capture gas produced during the flowback process (which would otherwise be flared or vented). Current regulatory requirements do not cover or require application of all available control technologies, and the regulatory environment is in flux federally and in California. For example, the California Air Resources Board is currently examining oil and gas sector emissions in order to develop standards to supplement recent federal regulations.

Significant data gaps exist with respect to air emissions from well stimulation. It is not clear how completely the current inventory methods cover air quality impacts from well stimulation, although it appears that at least some well stimulation air impacts will be covered by current inventory methods. Current inventory methods are not designed to separately analyze well stimulation emissions. As noted above, inventories are only infrequently verified experimentally. A small number of studies have directly measured emissions from well stimulation or in regions where well stimulation occurs. A larger body of studies exists on indirect (remote) estimates of oil and gas-related emissions in oil and gas-producing regions. There is no current consensus on where well-stimulation-related emissions specifically are largest, and significant uncertainty exists regarding emissions sources from oil and gas activities in general, although as noted above the experimental estimates of emissions have generally been found higher than inventory levels of emissions from oil and gas sources.

Preliminary quantitative assessment of the impacts due to well stimulation is made in the Volume III case studies for the San Joaquin Valley and South Coast regions.

3.2. Introduction

Well stimulation can impact air quality via emission of a large variety of chemical species. These species can have local, regional, or global impacts, mediated by the regional atmospheric transport mechanisms and the natural removal mechanisms relevant for that species. For clarity, this report groups species into four categories of interest, each with unique potential impacts.

1. Greenhouse gases (GHGs).

2. Volatile organic compounds (VOCs), and nitrogen oxides (NO_x) that cause photochemical smog generation.

3. Toxic air contaminants (TACs), a California-specific designation similar to federal designation of hazardous air pollutants (HAPs).

4. Particulate matter (PM), including dust.

GHGs have global impacts over long time scales through their effects on the radiation balance of the atmosphere. GHGs can also have significant local ecosystem effects, such as ocean acidification from rising atmospheric carbon dioxide (CO_2) concentrations. VOCs have regional impacts over the short- to medium-term through their effects on formation of photochemical smog and exacerbation of chronic health problems. In portions of this report dealing with California inventories of criteria pollutants, the term *reactive organic gases* (ROGs) will be used instead of VOC. ROGs are a defined class of species in California regulation, and have similar membership as other designations such as volatile organic compounds, nonmethane volatile organic compounds or speciated nonmethane organic compounds (ROGs, NMVOCs or SNMOCs). TACs and PM have local and regional health impacts mediated by transport and inhalation processes.

Some chemical species have impacts across multiple categories. For example, in addition to smog-formation potential, VOCs often also function over short and long time scales as GHGs through their eventual decomposition into CO_2. In these cases, species will be discussed primarily in terms of their most notable impact pathway. For example, though the degradation products of benzene can act as GHGs, benzene will be discussed as a TAC due to its larger importance in that domain. Similarly, PM has health as well as climate and aesthetic (visibility) impacts.

3.2.1. Chapter Structure

This introductory section first describes methods of classifying well-stimulation-related air impacts, and the major sources and types of emissions from oil and gas activities (remainder of Section 3.2). This is followed by an outline of current treatment of well-stimulation-related emissions in current California emissions inventories (Section 3.3).

Then, the report discusses the California regions likely to be affected by the use of well stimulation technology (Section 3.3.17) and the hazards associated with possible air impacts (Section 3.4). Next, the report outlines current best practices for managing air quality impacts of well stimulation (Section 3.5). This is followed by a discussion of gaps in data and scientific understanding surrounding well-stimulation-related air impacts (Section 3.6). Finally, a summary of findings and conclusions is presented (Sections 3.7 and 3.8).

3.2.2. Classification of Sources of Well Stimulation Air Hazards

Emissions from well stimulation can be classified as direct or indirect emissions. Direct impacts are uniquely associated with well stimulation and do not occur when oil and gas are produced without the aid of well stimulation. Examples of direct impacts of well stimulation include greenhouse gas emissions from equipment used to stimulate the well, and off-gassing of VOCs from stimulation fluids held in retention ponds and tanks. Indirect impacts stem from the other aspects of the oil and gas production process apart from well stimulation. Examples of indirect impacts include emissions from equipment used for well-pad construction, well drilling, and production of oil and gas; and off-gassing from produced water. This chapter will focus primarily on direct impacts, although important indirect impacts will also be discussed. This is because indirect impacts play an important role in air quality impacts in regions of significant well stimulation activities, and may be important determinants of long-run air quality impacts of well stimulation.

3.2.3. Greenhouse Gas Emissions Related to Well Stimulation

GHG and climate-forcing emissions to the atmosphere associated with well stimulation include the following: carbon dioxide (CO_2), methane (CH_4), carbon monoxide (CO), nitrous oxide (N_2O), VOCs, and black carbon (BC) (IPCC, 2013, pp. 738-740). For the purposes of GHG accounting, IPCC practice recommends binning all VOC species by mass of carbon (IPCC, 2013, pp. 738-740). Well stimulation practice can also result in the emission of species with negative climate forcing (i.e., cooling impacts) such as NO_x and organic carbon (OC) (IPCC, 2013). Nevertheless, the net effect of emissions from well stimulation is expected to be primarily warming. The climate impacts, listed using current 20-year and 100-year global warming potentials (GWPs) for well-stimulation-relevant gases, are listed in Table 3.2-1.

Table 3.2-1. Global warming potential of well-stimulation-relevant air emissions. (IPCC, 2013)

Gas species	GWP 20-yr	GWP 100-yr	Notes
Carbon dioxide (CO_2)	1	1	a
Methane, fossil (CH_4)	85	30	a
Nitrous oxide (N_2O)	264	265	a
Carbon monoxide (CO)	5.6 (+/-1.8)	1.8 (+/- 0.6)	b
Volatile organic compound (VOC)	16.2 (+/- 9.2)	5.0 (+/- 3.0)	c
Black carbon (BC)	1200 (+/- 720)	345 (+/- 207)	d
Organic carbon (OC)	-160 (+/- 68)	-46 (+/- 20)	d
Nitrogen oxides (NO_x)	-2.4 (+/ 30.3)	-8.2 (+/- 10.3)	e

a – From (IPCC, 2013) Table 8.A.1
b – From (IPCC, 2013) Table 8.A.4, for CO emissions in North America. CO GWP varies by the region of emissions due to regional differences in atmospheric processes.
c – From (IPCC, 2013) Table 8.A.5. Measured on per-kg of carbon basis. Estimate for North America VOC GWP varies by the region of emissions due to regional differences in atmospheric processes.
d – From (IPCC, 2013) Table 8.A.6. BC and OC GWPs taken from "four regions" study result, which encompasses East Asia, European Union (EU) + North Africa, North America, and South Asia.
e – From (IPCC, 2013) Table 8.A.3. Values for NO_x from North America.

3.2.4. Volatile Organic Compounds and Nitrous Oxides Emissions Related to Well Stimulation

VOCs are a large class of organic compounds that are variously defined. Thousands of chemical species are included in VOC definitions, with many of them present in hydrocarbon gases and liquids. VOCs include benign compounds as well compounds that are directly hazardous to humans. Hazardous VOCs will be discussed in the TACs section below. In certain conditions, VOCs react in the atmosphere to increase ozone formation. Some VOCs are transformed by atmospheric processes to particulate matter (PM).

Definitions of VOCs vary between regulatory regimes. U.S. Environmental Protection Agency (U.S. EPA) definitions list VOCs as organic species with vapor pressure greater than 10^{-1} Torr at 25°C and 760 mmHg (U.S. EPA, 1999). This regulatory definition exempts non-photochemically active species such as CH_4 and ethane (C_2H_6). This definition is designed to include organic species that are likely to exist in gaseous phase at ambient conditions. VOC emissions associated with well stimulation are numerous, with oil-and-gas-focused air studies measuring concentrations of many dozens of species (U.S. EPA, 1999; ERG/SAGE, 2011).

NO_x emissions associated with well stimulation activities derive primarily from use of engines powered by diesel or natural gas, which are used directly in well stimulation applications. Examples include drilling and workover rigs, fracturing trucks with large pumps for generating high fluid injection pressure, and other trucks of various kinds (e.g., proppant delivery trucks). Flaring can be another source of NO_x from oil and gas operations.

3.2.5. Toxic Air Contaminant Emissions Related to Well Stimulation

There are numerous TACs associated with well stimulation, which most commonly fall into the category of toxic organic compounds (TOCs) (U.S. EPA, 1999). These well-stimulation-associated TACs include many of the species defined as VOCs in the Clean Air Act (CAA) Amendments of 1990. TACs can be an acute or chronic concern for workers in the oil and gas industry, due to possibly frequent exposure to elevated concentrations of TACs, as well as long-term work in environments with TACs. TACs may also present a health concern for more remote persons that are less heavily exposed, such as those who live near oil and gas operations.

3.2.6. Particulate Matter Emissions Related to Well Stimulation

PM emissions in oil and gas development occur most commonly due to stationary combustion sources (CARB, 2013b). Other PM sources include heavy equipment in on-road and off-road operations, and land disturbance. Common sources of PM include diesel-powered equipment such as trucks, drilling rigs, generators, and other off-road equipment (e.g., preparatory land-moving equipment) (CARB, 2013b). PM may also be emitted through combustion (flaring) of wet gas (i.e., gas containing high molecular weight hydrocarbons). PM emissions are associated with respiratory health impacts and increased rates of mortality (see Chapter 6 on health impacts).

3.3. Potentially Impacted Resource—Air

3.3.1. California Air Quality Concerns

California has faced air quality concerns for many decades. Historical attention has focused primarily on smog-forming pollutants (e.g., VOCs and NO_x) and toxic air contaminants (TACs). A number of factors result in California air quality being among the most impacted in the nation. First, a large population of 40 million residents results in significant air emissions. Second, some California regions have unfavorable topography for air quality management, including large urban areas surrounded by mountains that prevent mixing and transport of emitted species. Third, the generally warm and sunny conditions in the state promote photochemical reactions and formation of smog. In some regions (noted below), agricultural activities can result in fine particulate pollution of concern.

More recently, regulatory efforts at the California Air Resources Board (CARB) have focused on GHG emissions. This has resulted in the development of broad industry-spanning GHG cap and trade regulations (CARB, 2014a), as well as oil and gas-specific regulatory efforts and ancillary transport-fuel regulations that affect oil and gas operators (CARB, 2014b).

CARB defines 35 Air Pollution Control Districts (APCDs) and Air Quality Management Districts (AQMDs), which are collectively called "air districts" (CARB, 2014c). These air districts are shown in Figure 3.3-1.

The two largest California oil and gas-producing regions are contained within the San Joaquin Valley Unified air district (henceforth SJV) and South Coast air district (henceforth SC). Significant oil production also occurs in the Santa Barbara and Ventura air districts. Non-associated (dry) natural gas production occurs in a number of Northern SJV air districts.

Large quantities of GHGs, VOCs, TACs, and PM are emitted by non-oil and gas sources in California, including primary industry, homes and businesses, and the transport sector.



Figure 3.3-1. California Air Pollution Control Districts (APCDs) and Air Quality Management Districts (AQMDs), collectively called "air districts." Image reproduced from CARB (2014c).

3.3.2. Estimating Current Impacts of Oil and Gas Operations on California Air Quality

Estimates of emissions for species of interest in California are tabulated, estimated, or inventoried for a variety of sources in the oil and gas sector. These estimates include:

1. Field-level estimates of GHG emissions produced for transport GHG intensity regulations (i.e., Low Carbon Fuel Standard).

2. State-level inventories of GHGs, ROGs, TACs, and PM compiled by the California Air Resources Board (CARB)

3. State-level surveys of emissions from oil and gas operators

4. Federal databases of GHG emissions and toxics releases (U.S. Environmental Protection Agency)

5. Detailed (spatially and temporally) inventories of air emissions for photochemical grid-based modeling of ozone formation.

This chapter covers the first four of these sources of information, with a strong focus on California-specific methods (first three sources in above list). These methods are described in order below, starting with field-level GHG intensity estimates. Each section describes the estimation methods and estimates derived for each species of interest, in the order of GHGs, VOCs, TACs, and PM. Table 3.3-1 shows a summary of where data were obtained for each type of assessment.

Table 3.3-1. Coverage of different assessment methods and key sources for each method.

Estimate type	Resulting data	Data source	Source
Field-level GHG estimates	t CO_2eq[1]. GHGs per year	DOGGR[2] production data	(DOGGR, 2014)
		CARB and OPGEE[3] model results of GHG intensities	(Duffy, 2013) (El-Houjeiri et al., 2013, 2014)
State-level emissions inventory	t CO_2eq. GHGs per year	CARB yearly GHG inventory	(CARB, 2014d,e) (CARB, 2013a)
	t ROG per year	CARB criteria pollutants inventory, incl. stationary and mobile sources	(CARB, 2013b)
	kg TACs per year	CARB overall toxics inventory (California Toxics Inventory)	(CARB, 2013c)
	kg TACs per year	CARB facility-level toxics reporting	(CARB, 2014j)
	t PM per year	CARB criteria pollutants inventory, incl. stationary and mobile sources	(CARB, 2013b)
Surveys of oil and gas operators	t CO_2eq. GHGs per year	CARB special survey of oil and gas operators	(Detweiler, 2013)
Federal GHG and toxics databases	Various	Not studied extensively in this report	(U.S. EPA, 2012)

[1]*CO_2-equivalent*

[2]*Department of Oil, Gas, and Geothermal Resources*

[3]*Oil Production Greenhouse Gas Emissions Estimator*

The scale at which emissions are assessed, and how emissions and their impacts are quantified, can influence study results. With regard to spatial scale, this chapter covers emissions at the statewide scale (in the case of GHG emissions) and at regional air district scales (in the case of criteria pollutants and air toxics). GHG emissions are assessed for the state as a whole, because GHGs are a global problem largely independent of location of emissions. In contrast, regional air districts are assessed for other pollutants, because these regions are designated by CARB as regions where atmospheric mixing and transport require the pollutants in a given region to be co-regulated. With regard to how emissions are quantified in this chapter, we examine mass-emissions rates and the fractional responsibility of oil and gas industry sources to the air quality problems studied.

Other spatial scales can matter for some pollutants. For example, emissions responsibility for oil and gas operations over smaller spatial scales can be higher than for an air district-wide measure. For example, when emissions are assessed for Kern County alone, there is larger responsibility of oil and gas sources than those found in this chapter for the San Joaquin Valley air district. At an even finer spatial scale, the specific location of an air

toxics source can be very important. These smaller-scale assessments can be found in the following locations:

- County-scale assessment of impacts: Volume III, San Joaquin Basin Case Study; Volume III, Los Angeles Basin Case Study.

- Local-scale assessment of emissions near sensitive populations: Volume II, Chapter 6 and Volume III, Los Angeles Basin Case Study and San Joaquin Basin Case Study.

Also, there are other ways to measure the importance of emissions than mass-emissions rates and the fraction of responsibility for a given industry. For example, in public health studies generally, the concentration of pollutant and the mass of pollutant being inhaled by the studied population is of concern, not necessarily the overall mass emissions rate in an air basin. Some health-damaging pollutants may therefore be of great concern at a local scale, even with small mass-emissions rates (e.g., oil and gas associated TACs such as benzene or toluene). See Volume II, Chapter 6, and Volume III, Los Angeles Basin Case Study for more information.

3.3.2.1. California Air Resources Board Field-Level Estimates of Greenhouse Gas Emissions from Oil Production

CARB produces an estimate of the greenhouse gas intensity of different producing oilfields in California, as part of the Low Carbon Fuel Standard (LCFS) effort (Duffy, 2013). The LCFS seeks to incentivize the production and consumption of transportation fuels with lower life cycle greenhouse gas intensity compared to conventional oil resources. Because the structure of the regulation assesses alternative fuels in comparison to oil-derived fuels, an accurate baseline emissions intensity for oil consumed in California is required.

As part of this effort, 154 California oil fields are assessed using the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), an open-source tool produced by researchers at Stanford University (El-Houjeiri et al., 2014, El-Houjeiri et al., 2013). OPGEE takes the properties of an oilfield and uses them to estimate the greenhouse gas emissions associated with producing, processing, and transporting the crude oil to the refinery inlet gate. While OPGEE cannot be used to assess emissions individually from pools that are facilitated or enabled with well stimulation technologies, it can be used to assess the emissions from oilfields within which well-stimulation-enabled pools exist.

Using information from Volume I, Appendix N, a total of 45 pools across California were determined to be facilitated by or enabled by well stimulation technologies. These pools are located in 28 California oilfields. While the pools themselves were found to account for ~20% of California oil production, the fields within which these pools exist were responsible for nearly 40% of California's oil production in 2012. The fields in which these pools exist, in general, contain lighter crude oil and result in lower greenhouse gas intensity than the average California oilfield (see Figure 3.3-2). The production-weighted-

average GHG intensity for well-stimulation-enabled pools is approximately 74% that of non-stimulated pools and 64% of California fields in general.

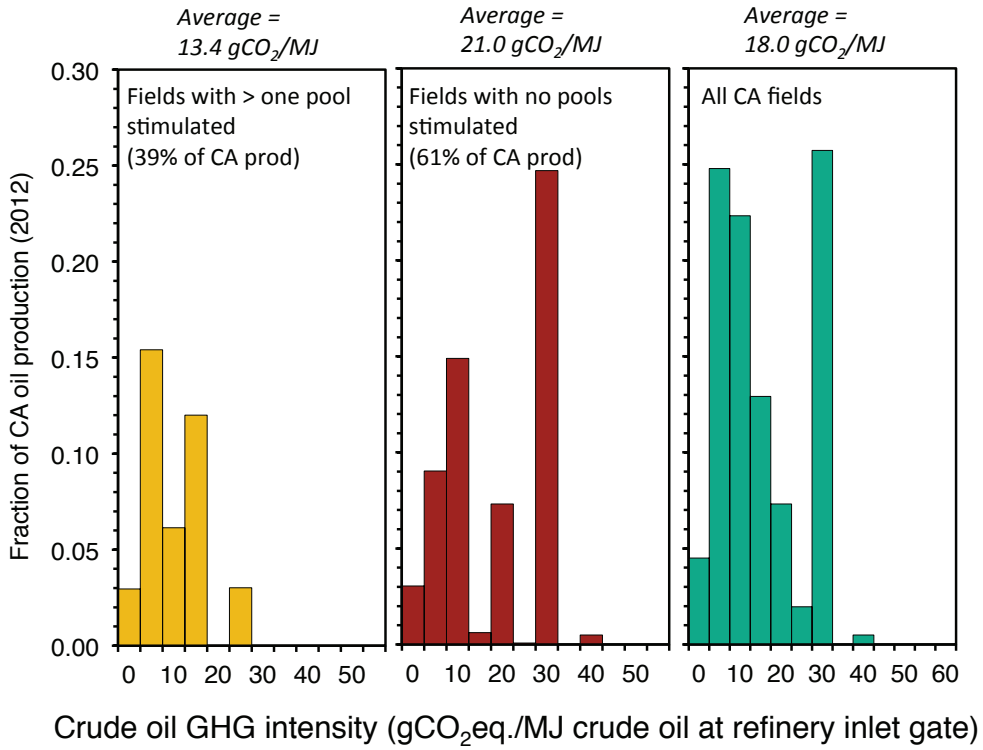


Figure 3.3-2. Distribution of crude oil greenhouse gas intensity for fields containing well-stimulation-enabled pools (left), those that are not stimulated (middle) and all California oilfields (right).

An important question regarding GHG emissions from stimulated wells is: "What would happen to GHG impacts if well stimulation were not practiced in the state?" If well stimulation were disallowed and consumption of oil and gas in California did not drop in response, the required oil would come from some other oilfields. That is, more oil and gas would be required from non-stimulated California fields or regions outside of California. This substitution would be the result of oil market shifts that would occur in response to the shift in California production.

Depending on the source of substituted oil and gas, overall greenhouse gas emissions due to oil production could increase if well stimulation were stopped. Computing the net GHG change associated with well stimulation therefore requires understanding of both in-state and out-of-state production, as well as the likely sources of "new oil." Thus, estimating the scale of impact requires a market-informed life cycle analysis (LCA). (This type of analysis is sometimes called "consequential" LCA.)

3.3.2.2. State-Level Emissions Inventories Produced by California Air Resources Board (CARB)

The California Air Resources Board (CARB) produces annual inventories of emissions of GHGs, VOCs, TACs and PM. These inventory methods and results are described in order below. In all cases, numerical results for 2012 will be presented, due to incomplete reporting for the year 2013 at the time of analysis.

The methods used to generate emissions inventories vary by the gas of interest. In general, emissions inventories collect data at the district level, and aggregate results to generate broader statewide estimates (CARB, 2014d). Direct measurements do not generally underlie emissions estimates included in inventories. For example, stationary source emissions are generally estimated using established emissions factors that are applied to the number of facilities of a given type in an analyzed region for a particular year. Similarly, rather than directly measuring vehicle emissions, databases of vehicle activities are used along with mobile source emissions factors (CARB 2014d). A full description of inventory methods is beyond the scope of this report, but where possible, methods and their impacts on emissions estimates are discussed.

3.3.2.2.1. CARB GHG Inventory for Oil and Gas Operations

CARB GHG inventories are produced on a yearly basis for the "six Kyoto gases": carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs) as well as nitrogen triflouride (NF_3) (CARB, 2014d). CARB GHG inventories report mass emissions of each gas, as well as CO_2-equivalent (CO_2eq.) emissions using IPCC Assessment Report (AR4) GWP factors.

Results from CARB GHG inventories can be queried by economic sector, as well as subsectors of various levels (CARB, 2014e). Direct well stimulation (WS) GHG emissions would be included in the subsector "Industrial > Oil & gas extraction." Additional indirect well-stimulation-related emissions, such as those resulting from induced hydrocarbon production, may occur more broadly (e.g., oil refining, refined product transport).

CARB GHG inventory methods

For each CARB-defined subsector, an "Activity" is defined. Activities with relevance for WS and for oil and gas activities include "Fuel Combustion" and "Fugitive Emissions." Within the "Fuel Combustion" activity, activity subsets exist to record the type of fuel consumed (e.g., natural gas, associated gas, distillate fuel). Each activity subset can result in emission of numerous GHGs. Combustion processes typically result in CO_2, CH_4, and N_2O, while fugitive emissions are a large concern due to their CH_4 content. The classification scheme under which direct well stimulation emissions would be classified in CARB GHG inventories is shown in Table 3.3-2. Many indirect emissions induced by WS activities would also be inventoried in these categories.

Table 3.3-2. CARB GHG inventory emissions of interest for WS (CARB, 2014e).

Main sector	Sub-sector Level 1	Sub-sector Level 2	Sub-sector Level 3	Main activity	Activity subset	GHG emitted
Industrial	Oil & gas extraction	Not specified	None	Fuel combustion	Associated gas	CH_4, CO_2, N_2O
		Not specified	None	Fuel combustion	Distillate	CH_4, CO_2, N_2O
		Not specified	None	Fuel combustion	Natural gas	CH_4, CO_2, N_2O
		Not specified	None	Fuel combustion	Residual fuel oil	CH_4, CO_2, N_2O
		Petroleum gas seeps	Fugitives	Fugitive emissions	NA	CH_4
		Process losses	Fugitives	Fugitive emissions	NA	CH_4, CO_2, N_2O
		Storage tanks	Fugitives	Fugitive emissions	NA	CH_4
		Wastewater treatment	Fugitives	Fugitive emissions	NA	CH_4

The CARB oil and gas GHG emissions inventory methodology is based on two key data sources and methodologies. First, CARB uses IPCC Guidelines with state and federal data sources (IPCC, 2006). More recently, CARB has augmented IPCC-based methods with more detailed reporting under the Mandatory Reporting Regulation (MRR), a state-level regulation requiring detailed reporting of GHG emissions by large emitters.

The IPCC methodology primarily tracks energy use. Briefly, energy use is gathered for a given sector, and this use is multiplied by a fuel-specific emissions factor for each fuel type (CARB, 2014f, pp. 56-58). To complete its oil and gas GHG inventory, CARB obtains fuel use data for oil and gas activities from the following state and U.S. federal sources: U.S. Energy Information Administration (EIA), California Energy Commission, and the California Department of Oil, Gas, and Geothermal Resources (DOGGR) (CARB, 2014f, p. 58). Fugitive emissions are estimated in this methodology using information generated from the California Emission Inventory Development and Reporting System (CEIDARS) database (CARB, 2014f, p. 59), which is developed for tracking criteria pollutants such as VOCs. See significant additional discussion of CEIDARS below.

More recently, the California GHG inventory leverages California MRR datasets relevant to well stimulation and oil and gas activities. MRR data are gathered from the category of processes entitled “Petroleum and Natural Gas Systems” (CARB, 2014g, sect. 95101). MRR data reporting is required from all oil and gas operators whose stationary and process emissions of CO_2, CH_4 and N_2O exceed 10,000 tonnes (t) of CO_2eq. per year, or whose stationary combustion, process, fugitive, and vented emissions of the above gases equal or exceed 25,000 tCO_2eq. per year (CARB, 2014g, sect. 95101). Detailed methods are given for estimation of emissions from various oilfield operations (CARB, 2014g, sect. 95150), with different oil and gas subsegments required to report information using a separate set of individual methodologies (CARB, 2014h). These methods rely on emissions-factor-like approaches for some categories, as well as engineering-based equations for other categories.

Coverage of well stimulation activities in GHG inventory

The CARB GHG inventory covers oil and gas emissions using a variety of mechanisms. With regard to combustion emissions analyzed under IPCC methods, the most important quantities are fuel consumption during well stimulation activities (e.g., diesel fuel to operate hydraulic fracturing operations). Distillate fuel consumption in California for the CARB GHG inventory is taken from U.S. EIA dataset "Adjusted Sales of Distillate Fuel Oil by End Use" (CARB, 2014f, p. 58). This dataset reports distillate fuel consumption partitioned by sector at the state level (U.S. EIA, 2014a). The end use sector of interest is the U.S. EIA-defined "Oil Company" sector, which is defined as per U.S. EIA definitions:

> *"An energy-consuming sector that consists of drilling companies, pipelines or other related oil companies not engaged in the selling of petroleum products. Includes fuel oil that was purchased or produced and used by company facilities for operation of drilling equipment, other field or refinery operations, and space heating at petroleum refineries, pipeline companies, and oil-drilling companies. Sales to other oil companies for field use are included, but sales for use as refinery charging stocks are excluded." (U.S. EIA, 2014b)*

This U.S. EIA definition is sufficiently general such that it should include diesel fuel use for WS activities. Because of the aggregated nature of the U.S. EIA diesel fuel consumption dataset, strictly maintained to provide operator confidentially, no greater specificity can be provided about how accurately this portion of the CARB GHG inventory accounts for combustion GHG emissions directly related to WS. If some California WS-related operators did not report fuel use to the U.S. EIA under these requirements, their use would not be counted.

Non-combustion emissions estimates that are not modeled using mandatory reporting regulation (MRR) methods are derived from the CEIDARS database of criteria air pollutants (CARB, 2014f, p. 59). Fugitive emissions of CH_4, CO_2 and other gases (VOCs) that arise during oil and gas operations are estimated using CEIDARS data. The CEIDARS total organic gases (TOG) emissions inventory (CARB, 2014f) is used for this purpose. This inventory is discussed further below, because this TOG inventory includes VOCs as well as methane emissions. A speciation model (CARB, 2000) is used to estimate emissions of GHGs from TOG emissions sources (CARB, 2014f, p. 59). As discussed below, the coverage of well-stimulation-related activities in the criteria pollutants inventories is uncertain.

Starting a few years ago, the above methods are being supplemented by data reported directly by operators through CARB's MRR program (CARB, 2014f, p. 59). MRR reporting requires reporting of fuel consumed by operators above a size threshold. MRR sources are also required to estimate "fugitive emissions from pipes, storage tanks, and process losses in the oil & gas extraction…sectors" (CARB, 2014f, p. 59), using a series of methods that

have been harmonized with federal emissions reporting requirements. It is unknown what fraction of wells drilled in California are drilled by companies reporting to MRR databases, although most data from inventories are still derived from non-MRR sources.

Most relevant to well stimulation activities, flowback emissions from natural-gas well completion, post-well-stimulation activities are to be computed and reported in methods equivalent to U.S. EPA federal reporting requirements using the U.S. EPA GHGRP (GHG reporting program) (GHGRP Subpart W, see below). These methods are a mix of empirical and engineering-based methods for estimating emissions given technology characteristics and operating conditions (e.g., operating pressure).

Given the above level of detail required as part of MRR reporting, it is likely that many well-stimulation-related emissions sources will be included in MRR data. Some well-stimulation-related emissions may not be covered if subcontractor emissions occurring during well stimulation do not meet reporting thresholds related to operator size. It is not possible to discern the exact coverage (or lack thereof) of well stimulation activities within the MRR dataset, due to the aggregated nature of public data reporting.

Results of CARB GHG inventory

Statewide GHG emissions in California totaled 466 Mt CO_2eq. in 2012. The "Industrial > Oil & gas extraction" sector was responsible for ~17 MtCO_2eq., or somewhat less than 4% of statewide emissions (CARB, 2014d).

The dominant contributor to the oil and gas GHG inventory was CO_2 emissions resulting from fuel use. Fuel use in oil and gas development in California is heavily influenced by combustion of fuels for thermal enhanced oil recovery. Fugitive emissions from oil and gas totaled <1.5 Mt CO_2eq., or 0.3% of statewide emissions (CARB, 2014d). As shown in Figure 3.3-3, the overall trend in California oil and gas GHG emissions is downward over time, likely due to decreasing California oil and gas production.

If more recent IPCC AR5 GWPs (see Table 3.2-1) are used instead of CARB-applied IPCC AR4 GWPs, CO_2-equivalent GHG emissions from the California oil and gas industry increase by only a small amount between 2000 to 2012—specifically, the yearly increase ranges from 0.5% to 1.2%. Note that emissions sources classified as "combustion" sources can result in CH_4 emissions due to incomplete combustion or direct loss from combustion equipment.

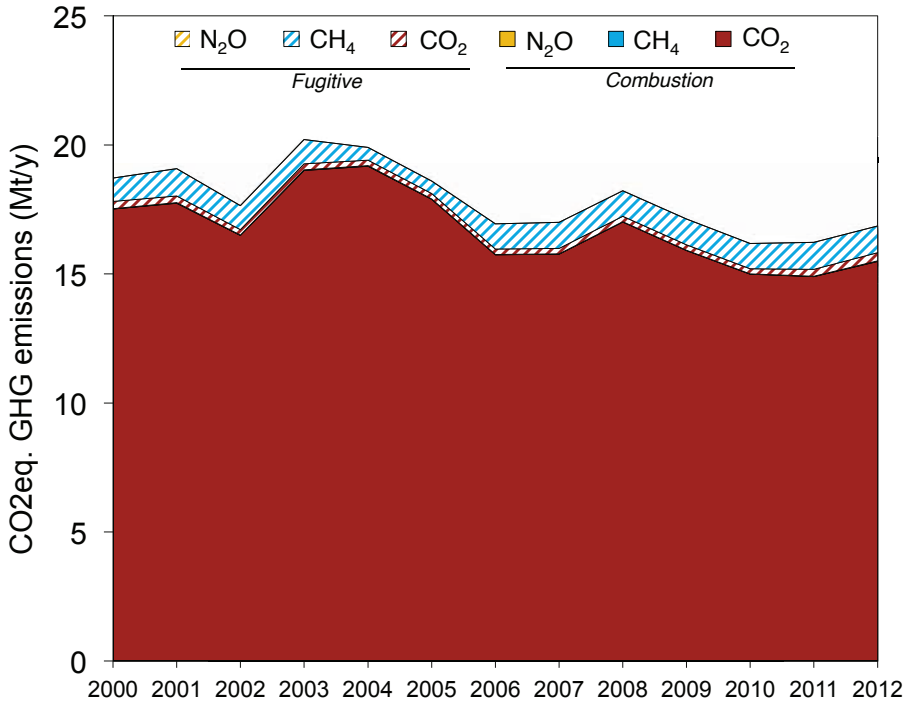


Figure 3.3-3. Emissions from "Oil and Gas Extraction" sources as reported in California GHG inventory. Source: plotted from (CARB, 2014d). Emissions in million metric tonnes per year (109 kg per year). Oil and gas extraction activities account for <4% of total statewide GHG emissions."

Summary of CARB GHG inventory coverage

The CARB GHG inventory is likely to include emissions from many well stimulation activities. To summarize the discussion above:

- Baseline data for the GHG inventory data appear to derive from a combustion emissions inventory that uses (among other sources) federally reported fuel consumption data for a broadly defined oil and gas sector.

Oil and gas emissions are also subject to (for large producers) MRR requirements, which specify detailed reporting methodologies and broad coverage of combustion and noncombustion sources. Even given this broad reporting requirement and comprehensive coverage, it is not clear that GHG emissions from all well stimulation activities are reported as part of the CARB GHG inventory. For example:

- Smaller producers are exempt from MRR requirements. Given that the criteria pollutants inventory does not definitively include well stimulation activities, these operators could be a source of missing well-stimulation-related GHG emissions.

- MRR data reporting has some known coverage gaps. For example, MRR data reporting includes flowback emissions during completion of well stimulation applied to natural gas wells. However, MRR does not appear to require reporting of flowback emissions from well stimulation applied to oil wells.

3.3.2.2.2. CARB Inventories for VOC and NOx (Smog-Forming) Emissions

CARB inventories of criteria air pollutant emissions are performed on a yearly basis for each air district. Detailed estimates of emissions by sectors, sources, and subsources are presented for a variety of species, including total organic gases (TOG), reactive organic gases (ROG), NO_x, SO_x, CO, and PM. CARB documentation suggests that CARB ROG emissions are very similar to (though not exactly equal to) U.S. EPA-defined VOC emissions (CARB, 2000). TOG emissions include ROGs/VOCs, as well as non-photochemically active organic gases such as CH_4 and C_2H_6 (CARB, 2000). For the remainder of this section, we will use the CARB terminology of ROG.

CARB criteria pollutant inventory methods

The CARB criteria air pollutant inventory is divided broadly into three categories: stationary sources, area-wide sources, and mobile sources. These categories are then broken down into sectors, subsectors, and sources. Inventory methods vary for each broad source category, as well as within each source category. The most relevant categories for smog-forming emissions from well stimulation and oil and gas operations are given in Table 3.3-3. It does not appear that area-wide sources are relevant for well stimulation or oil and gas operations. Detailed lists of contributing equipment or technologies for each subsector are presented below.

Table 3.3-3. CARB criteria pollutant inventory sector/subsector pairings of interest for oil and gas and well stimulation emissions.

Broad category	Sector	Subsector
Stationary sources	Fuel combustion	Oil and gas production (Combustion)
	Petroleum production and marketing	Oil and gas production
Mobile sources	On-road motor vehicles	Various
	Other mobile sources	Off-road equipment

Compared to the GHG inventory described above, the criteria pollutants inventory reports emissions sources in considerable detail. For example, in the stationary source criteria pollutants inventory, emissions are tracked for multiple types of combustion technologies (i.e., reciprocating engines, boilers, turbines, steam generators) rather than a broad "combustion emissions" category. Also, more fuels are represented, with fuel subspecification available for types of distillate fuel or types of gaseous fuel. Lastly, different emissions mechanisms within a given equipment category are represented. For

example, ROG emissions from tanks are classified into breathing and working losses for both fixed and floating roof tanks.

To determine the coverage of stationary-source oil and gas emissions, all sources classified in the "Stationary sources > Fuel combustion > Oil and gas production (Combustion)" and "Stationary sources > Petroleum production and marketing > Oil and gas production" subsectors are summed for the SJV and SC regions. The resulting sources and materials (e.g., fuel, working fluid, or chemical) responsible for emissions in these subsectors are listed in Table 3.3-4. While other possible sources might exist in other air basins, these two air basins are indicative of California oil and gas operations and are responsible for the majority of state oil production. The list of sources in Table 3.3-4 is therefore likely to be representative of statewide oil and gas sources (CARB, 2013b).

Table 3.3-4. CARB ROG/CO stationary source inventory emissions sources and material drivers of emissions within the broad categories "Oil and Gas Production" and "Oil and Gas Production (Combustion). Sources and materials taken from SJV and SC air district data.

Sources	**Materials**
Reciprocating engines	Diesel/Distillate oil (unspecified) Gasoline (unspecified) Natural gas Gaseous fuel (unspecified) Propane
Turbine engines	Natural gas Diesel/Distillate oil (unspecified)
Boilers	Natural gas Propane Process gas Residual oil #6 (Bunker C)
Process heaters	Natural gas Residual oil (unspecified)
Steam generators	Natural gas Process gas
Fugitives – Oil/water separator	Crude oil (unspecified)
Fugitives – Wet gas stripping/field separator	Gaseous fuel (unspecified)
Fugitives – Pumps	Crude oil (unspecified)
Fugitives – Compressors	Crude oil (unspecified)
Fugitives – Well heads	Crude oil (unspecified)
Fugitives – Well cellars	Crude oil (unspecified)
Fugitives – Valves	Natural gas Crude oil (unspecified)
Fugitives – Fittings	Crude oil (unspecified)
Fugitives – Sumps and pits	Crude oil (unspecified)
Fugitives – Miscellaneous	Crude oil (unspecified)
Floating roof tanks – Working	Organic chemicals (unspecified)

Fixed roof tanks - Working	Diesel #2 Crude oil – RVP 5 Ethylene Glycol Aromatics (unspecified) Acid (unspecified) Jet Naphtha (JP-4) Glycols (unspecified)
Floating roof tanks - Breathing	Organic chemicals (unspecified)
Fixed roof tanks - Breathing	Diesel #2 Crude oil – RVP 5 Organic chemicals (unspecified) Benzene Methanol Jet Naphtha (JP-4)
Tank cars and trucks - Working	Diesel/Distillate oil (unspecified) Gasoline (unspecified) Crude oil (unspecified)
Natural gas prod.	Natural gas
Steam drive wells	Crude oil (unspecified)
Cyclic steam wells	Crude oil (unspecified)
Oil production - Heavy oil test	Crude oil (unspecified)
Vapor recovery/flares	Process gas Liquefied Petroleum Gas (LPG)
Other	Material not specified Crude oil (unspecified) Mineral and metal products (unspecified) Natural gas

Mobile sources of criteria pollutants are estimated by air district for a variety of on-road and “other” mobile sources.

On-road vehicles are classified by duty class (CARB, 2013b), e.g., light duty trucks, medium-duty trucks, or heavy duty trucks. It is probable that transport of light equipment and personnel for well stimulation activities would take place using light duty trucks, while proppant, steel well casing, bulk materials, or chemicals would be hauled in heavy duty trucks. On-road truck emissions are subspecified at various levels of detail. For example, the “Heavy Heavy Duty Diesel Trucks” category has a variety of subcategories, including agriculture, construction, and port use. In contrast, “Light Heavy Duty Diesel Trucks” are not subspecified in results by the industry which employs them.

No on-road categories reported petroleum-related subcategories, so use of on-road trucks for oilfield activities such as well stimulation are not able to be determined from inventory results. At least some of the reported on-road criteria pollutant emissions are likely due to well stimulation or oil and gas activities, but inventory results are not specific enough to differentiate these uses. With access to the underlying models, examining truck use by industry sector may be possible.

The category of "Other mobile sources," however, does present oil and gas-relevant categorization under the heading of off-road equipment. The relevant category is "Other mobile sources > Off-road equipment > Oil drilling and workover." The types of equipment in this category are listed in Table 3.3-5. A variety of oilfield equipment (e.g., pumps, lifts, rigs) are modeled for a variety of equipment sizes. Mobile source emissions are modeled using a methodology that tracks populations of vehicles, vehicle usage and load factors, and vehicle distribution within the state air districts, etc. (CARB, 2010).

The vehicle database DOORS (Diesel Off-road On-line Reporting System) tracks the numbers of off-road vehicles in the state, as well as their rated horsepower for categorization (CARB, 2010). In the model base year (2010), documentation states that oilfield equipment in DOORS included 184 drilling rigs and 638 workover rigs (adjusted from reported values based on CARB estimated non-compliance rates). The load factor (fraction of maximum engine output) assumed is 50% for oilfield equipment (CARB, 2010, p. D-10). Oilfield rigs are assumed to operate for ~1,000 hours per year (CARB, 2010, p. D-14). Oil drilling equipment is allocated to the following air basins: SJV, 61.1%; Sacramento Valley, 14.5%; SC, 13%; and South Central Coast, 8.5% (CARB, 2010, p. D-33). Consulting the underlying DOORS database confirms that only these drilling rigs and workover rigs are included in the newest (2011) version of the DOORS database.

Table 3.3-5. CARB mobile source inventory emissions sources within the category "Off road, oil drilling and workover, diesel (unspecified)" taken from SJV and SC air district data.

Sources	Sizes
Compressor (workover)	D25, D120, D175, D250, D500, D750, D1000
Drill rig	D120, D175, D250, D500, D750, D1000
Drill rig (mobile)	D50, D120, D175, D250, D500, D750, D1000
Workover rig (mobile)	D50, D120, D175, D250, D500, D750, D1000
Generator (drilling)	D50, D120, D175, D250, D500, D750
Generator (workover)	D120, D175, D250, D500, D750, D9999
Lift (drilling)	D120, D175, D250, D500, D750
Other workover equipment	D120, D175, D250, D500, D750, D1000
Pressure washers	D250
Pump (drilling)	D120, D175, D250, D500, D750, D9999
Pump (workover)	D120, D175, D250, D500, D750, D9999
Snubbing	D120
Swivel	D120, D175, D250, D500

Coverage of WS activities in ROG inventory

From the stationary-source specification provided in Table 3.3-4, it appears likely that at least some well-stimulation-related activities are represented in the stationary source criteria pollutant inventory. For example, flowback emissions might be included in the category "Fugitives—Well heads" or "Fugitives—Oil/Water Separator." The

fundamental data underlying these categories are summed from facility-level data. CARB methodologies do not describe exactly what is or is not included in each source category, nor how emissions estimates might have been updated in light of development of new technologies such as well stimulation. Users are recommended to contact a particular air district for more information on how a particular source was estimated.

Regarding on-road mobile sources, no information is available about how well-stimulation-related on-road emissions might be counted in the inventory.

Regarding off-road and oilfield equipment, the information presented in Table 3.3-5 suggests that at least partial coverage of well-stimulation-related equipment is provided in the mobile source inventory (e.g., rigs, pumps, generators). The exact coverage of well stimulation equipment in these databases cannot be determined.

CARB ROG inventory results are presented in mass of ROG per year. Calculations of impacts based on species-specific reactivities have been used in California regulation for assessing the actual ozone-formation potential for different species (CARB, 2011). For this report, we use the reported mass emissions of ROGs.

Results of CARB criteria-pollutant inventory: ROG and NO_x

Criteria pollutant inventory results show that oil and gas operations are generally responsible for a minority of stationary ROG and NO_x emissions. In 2012 in the SJV Unified air district, upstream oil and gas emissions totaled 25.1 t ROG/d, representing ~7.7% of ROG emissions from anthropogenic sources and 2.3% of ROG emissions from all sources (natural and anthropogenic). In the SC air district, the equivalent values were 0.23% and 0.16%, respectively (CARB, 2013b). A breakdown of ROG emissions from oil and gas operations in these two air districts is shown in Figure 3.3-4 (SC) and Figure 3.3-5 (SJV) at two levels of specificity. The left-hand side of each figure groups sources listed in Table 3.3-4 into broader categories. Major stationary sources in the SJV air district are mixed evenly between fugitive emissions and production wells. Major stationary sources in the SC air district include fugitive sources, tanks, and engines.

Note that these stationary emissions only include upstream oil and gas production and surface processing emissions; they do not include petroleum refining emissions nor consumption of the refined fuels that are produced from oil (e.g., fugitive VOC emissions from automobile fueling).

Speciation of stationary source fugitive TOG emissions is determined based on emissions source using established standard speciation profiles (CARB, 2014i, see Figure 3.3-6). These speciation profiles have lower CH_4 concentrations than other observations (see below), perhaps due to the dominance of oil and heavy oil production over dry gas production in California.

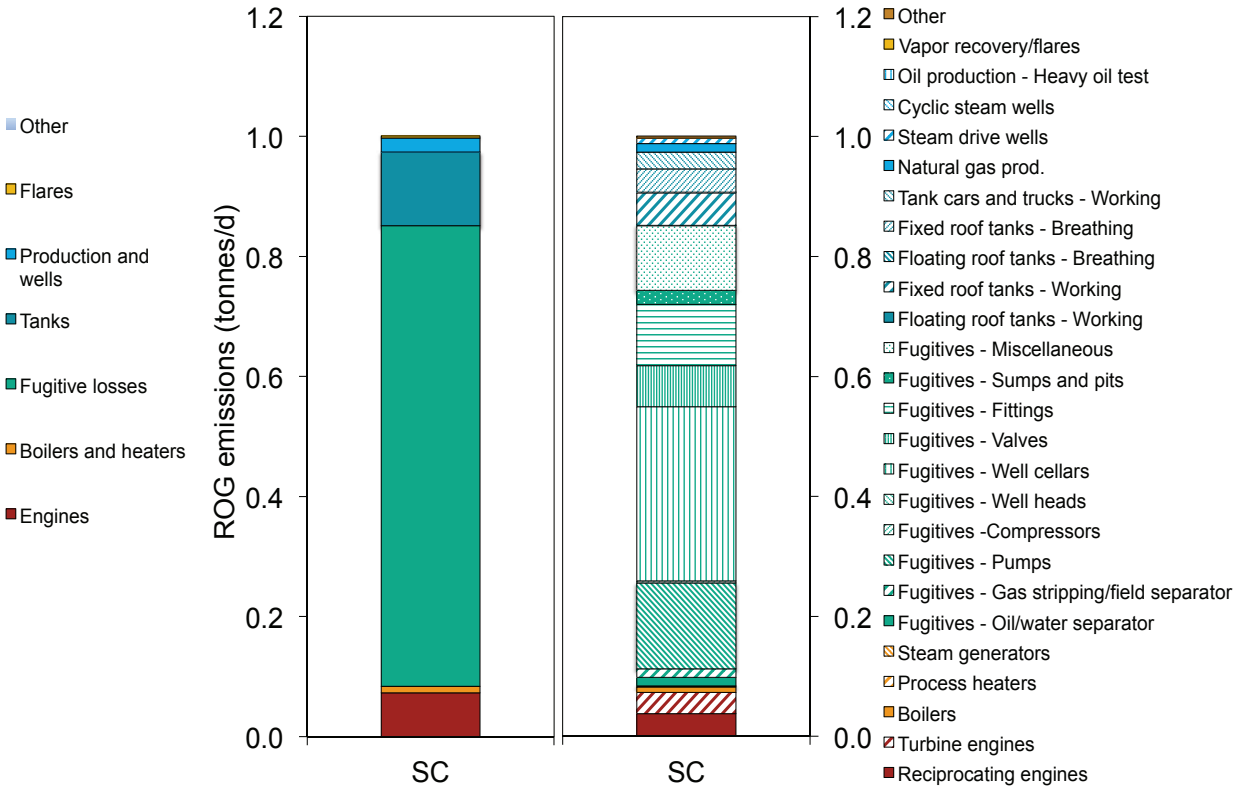


Figure 3.3-4. Stationary source 2012 emissions of reactive organic gas (ROG) from all stationary oil and gas production sources in the South Coast air district. Emissions in tonnes per day (1,000 kg/d).

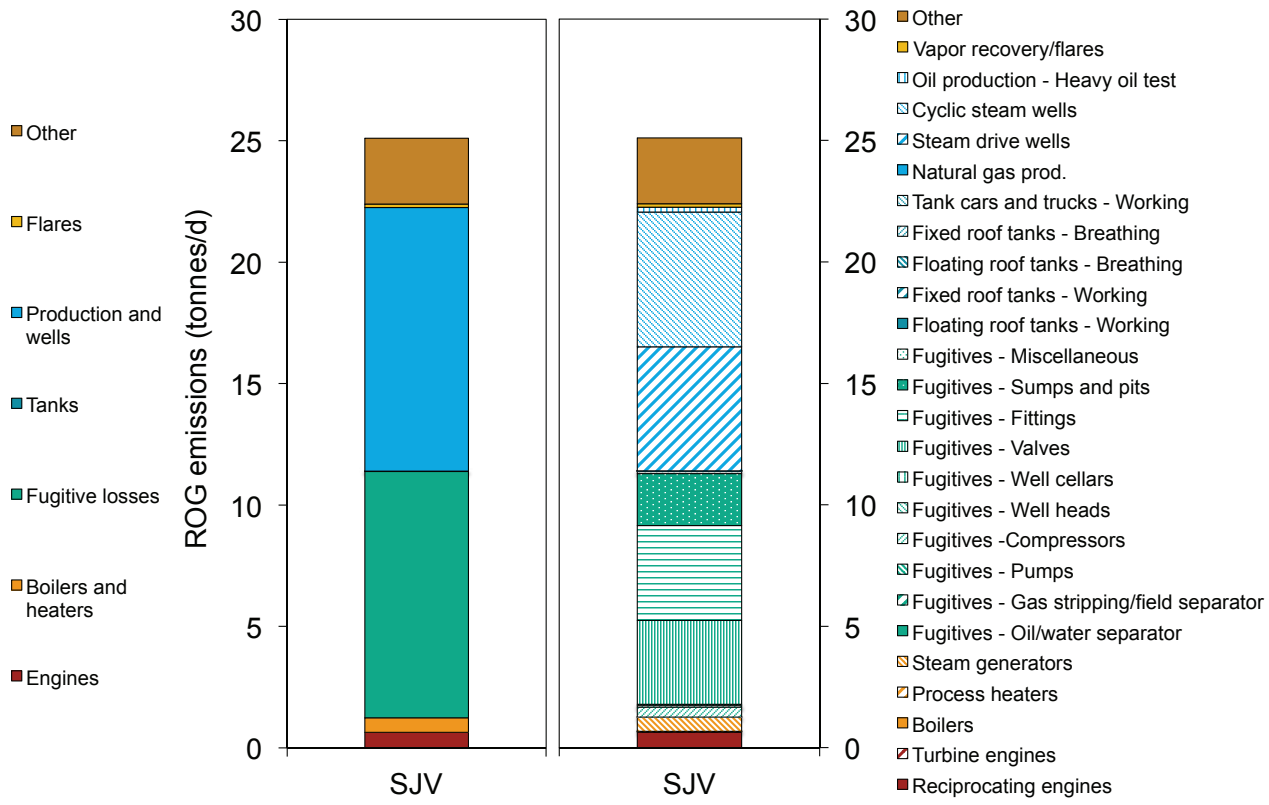


Figure 3.3-5. Stationary source 2012 emissions of reactive organic gas (ROG) from all stationary oil and gas production sources in the San Joaquin Valley Unified air district. Emissions in tonnes per day (1,000 kg/d).

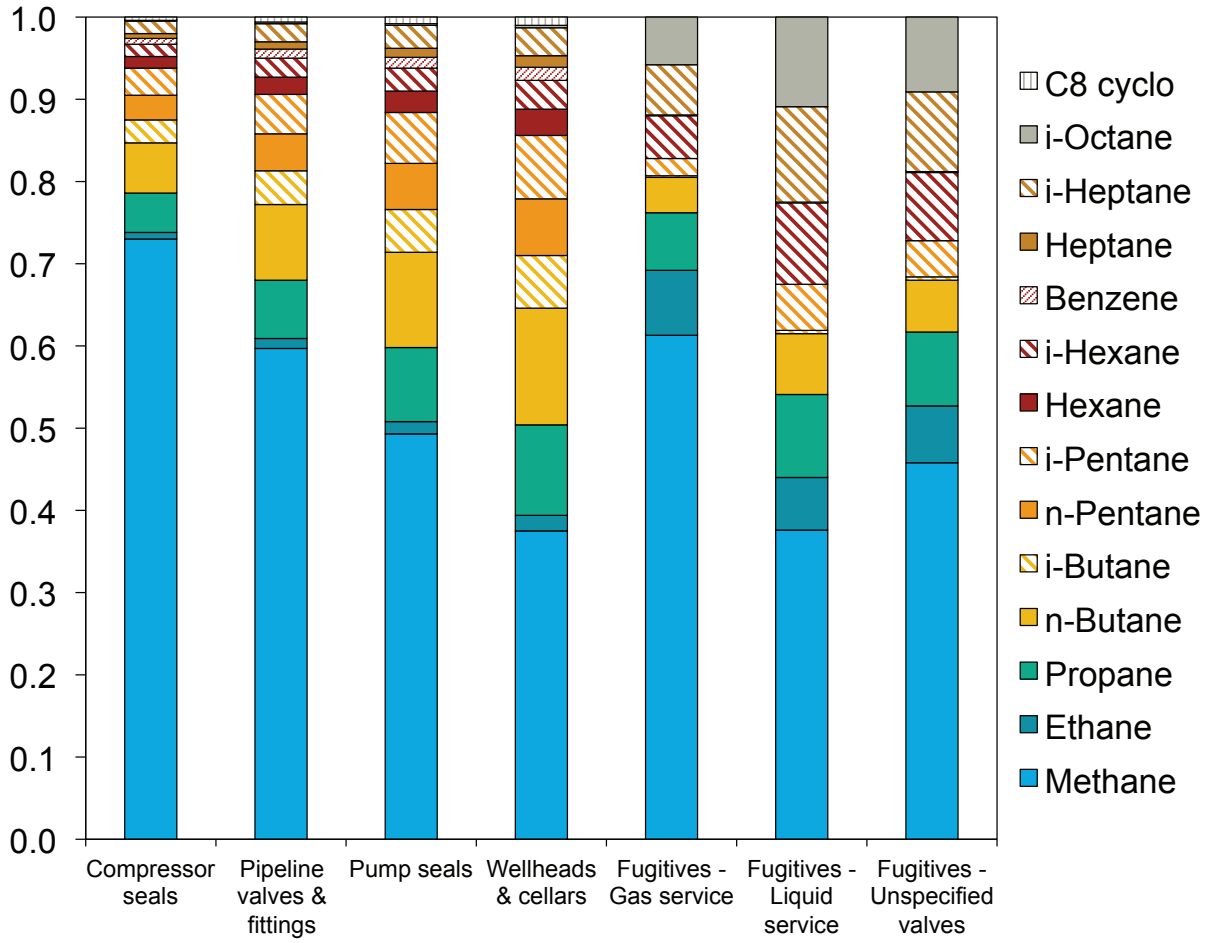


Figure 3.3-6. Stationary source speciation of TOG fugitive oil and gas production sources. Source: (CARB, 2014i)

Stationary source NO_x emissions from oil and gas sources can be computed similarly to the stationary source ROG/VOC emissions methods. Using the above methods, stationary source emissions in the "Oil and Gas Production" and "Oil and Gas Production (Combustion)" categories make up 1.1% and 0.3% of the stationary source NO_x emissions in the SJV and SC regions, respectively (CARB, 2013b).

Emissions from on-road vehicles associated with well stimulation or with the oil and gas industry cannot be partitioned from the inventory, but do represent some fraction of on-road ROG/VOC emissions.

ROG emissions from off-road oil and gas sources for the SJV and SC regions are shown in Figure 3.3-7. Off-road oil and gas ROG emissions in SJV region are 0.59 t per day. In the SJV air district, this is equivalent to 0.75% of mobile source ROG emissions and 0.18% of ROG/VOC emissions from all sources. In the SC region, ROG emissions from off-road

oil and gas sources are 0.08 t per day: 0.04% of mobile-source ROG/VOC emissions, and 0.02% of total ROG emissions from all sources.

Using a reasonable assumption of the share of in-state on-road trucks used by the oil and gas industry, these sources will make up a small fraction of mobile source ROGs in California. This conclusion is not surprising, due to the relatively small size of the oil and gas sector in California compared to the many other industries supporting 40 million California residents.

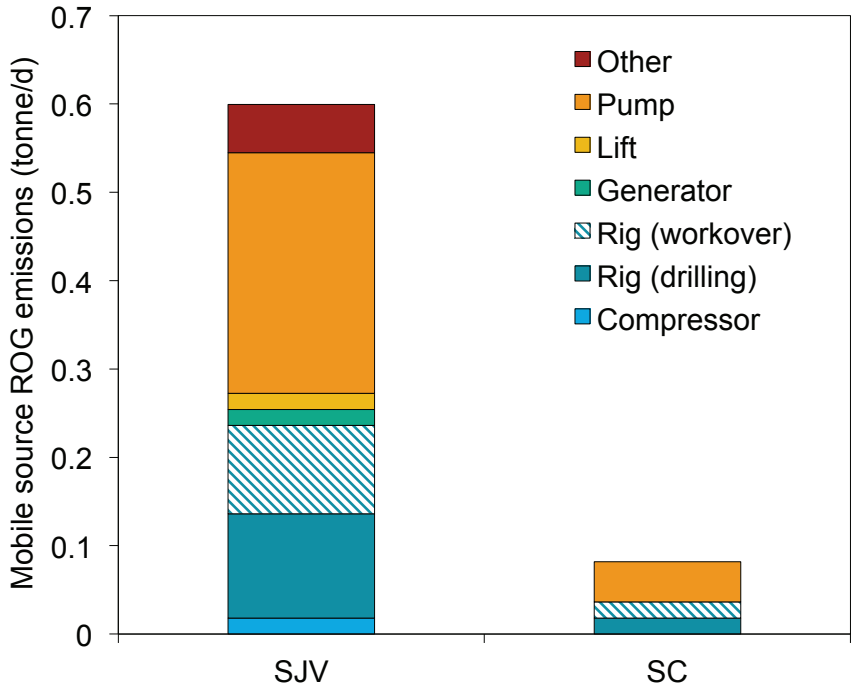


Figure 3.3-7. Mobile source 2012 emissions of reactive organic gas (ROG) from all sources within the categorization "Off road, oil drilling and workover, diesel (unspecified)" Emissions in tonnes per day (1,000 kg/d). Source: CARB (2013b).

The oil and gas industry represents a larger fraction of mobile source NO_x emissions and total NO_x emissions than ROG/VOC emissions. Using similar methods to those used above, NO_x emissions from off-road oil and gas equipment are 7.3 and 1.6 t per day in the SJV and SC regions, respectively. In the SJV region, this represents 2.9% of mobile source NO_x, and 2.5% of total NO_x emissions. In the SC region, oil and gas NO_x emissions of 1.6 per day represent 0.3% of total mobile sources and 0.3% of all NO_x sources (CARB, 2013b).

Summary of CARB criteria pollutant inventory coverage

A summary of all criteria pollutant emissions from oil and gas operations (stationary and mobile) is shown in Table 3.3-6.

Table 3.3-6. CARB criteria pollutant overview in emissions of criteria pollutants in t per day (1,000 kg/d). Includes all anthropogenic as well as all sources, natural and anthropogenic.

		ROG	**NO_x**	**SO_x**	**PM**	**PM10**	**PM2_5**
SJV	Oil and gas - Stationary	25.1	3.2	2.9	1.9	1.8	1.8
SJV	Oil and gas - Mobile	0.6	7.3	0.0	0.2	0.2	0.2
SJV	Total anthropogenic	324.9	295.2	9.4	479.8	255.7	68.7
SJV	Total anthropogenic + natural	1112.8	306.2	12.8	517.5	291.9	99.4
SJV	Percentage of anthropogenic	7.9%	3.6%	31.2%	0.4%	0.8%	3.0%
SJV	Percentage of total	2.3%	3.4%	23.0%	0.4%	0.7%	2.0%
		ROG	NO_x	SO_x	PM	PM10	PM2_5
SC	Oil and gas - Stationary	1.0	1.7	0.0	0.1	0.1	0.1
SC	Oil and gas - Mobile	0.1	1.6	0.0	0.0	0.0	0.0
SC	Total anthropogenic	438.2	517.7	17.7	228.3	157.6	66.7
SC	Total anthropogenic + natural	613.8	521.8	19.8	257.1	185.3	90.1
SC	Percentage of anthropogenic	0.2%	0.6%	0.1%	0.1%	0.1%	0.2%
SC	Percentage of total	0.2%	0.6%	0.1%	0.0%	0.1%	0.1%

The CARB criteria pollutant inventory is likely to include some emissions from well stimulation activities, but the level of coverage is uncertain. To summarize the above:

- Oil and gas criteria pollutant emissions are estimated using detailed categorization in stationary source and off-road mobile source databases. Criteria pollutant emissions from on-road oil and gas sources cannot be determined because the on-road emissions databases do not partition emissions by sector.

- Given the detailed categorization of stationary source emissions (e.g., “Fugitives—Well head”) and off-road mobile source emissions (e.g., “Rigs—Workover”) , it is possible that well-stimulation-related sources are being tracked. The level of well-stimulation-related coverage cannot be determined from reported data.

3.3.2.2.3. CARB Inventories for TACs

A variety of TACs can be released from well stimulation activities. Key TACs include VOC or fugitive hydrocarbon emissions, particulate matter (discussed separately below), and emission of substances used in hydraulic fracturing fluids.

Because of the large scope and complexity of TACs emissions (both in number of species and number of emissions processes), all results in this section are computed for 10 indicator TACs that can be emitted from oil and gas sources. These indicator TACs include the largest 5 sources from a recent EPA risk assessment for oil and natural gas production (U.S. EPA, 2011). This source lists oil and gas production associated TACs ordered by rate of emissions across 990 facilities in an EPA dataset (U.S. EPA, 2011, Table 4.1.-1). Next, ethyl benzene is included as in indicator TAC due to its importance in the suite of BTEX (benzene, toluene, ethylbenzene, and xylenes) hydrocarbon emissions (ethyl benzene was also ranked 6th in the EPA list by emissions rate). Hydrogen sulfide is included as an important hydrocarbon-related compound with potential health effects. We note that hydrogen sulfide is not technically classified as a TAC (U.S. EPA, 2014), but serious human health impacts are associated with breathing small amounts of hydrogen sulfide, resulting in stringent safety requirements and controls around hydrogen sulfide (H2S) releases. Lastly, four indicator species are added that were found upon inspection of CARB databases to be significantly driven by oil and gas sector sources.

The resulting 10 indicator TACs species are: 1,3-butadiene, acetaldehyde, benzene, carbonyl sulfide, ethyl benzene, formaldehyde, hexane, hydrogen sulfide, toluene, and xylenes (mixed). This list is not meant to be exhaustive of all possible species of interest, but indicative of the possible contributions of oil and gas sources.

CARB TAC inventory methods

TACs emissions by species for a broad variety of sources are reported in the CARB California Toxics Inventory (CTI). The CTI is not computed frequently: data were reported most recently for year 2010 (CARB, 2013c). Unlike the facility-scale "hot spot" dataset (see below), the CTI includes a variety of nonstationary sources, such as area-wide sources and mobile sources (gasoline, diesel, off-road equipment, etc.).

The CTI reports emissions by air district for ~340 toxic species (CARB, 2013c). These data are compiled from facility-level data noted above, as well as mobile sources and dispersed stationary sources such as homes and nonreporting businesses. TACs from mobile sources, which are not otherwise subject to air toxics reporting requirements, are estimated by applying speciation factors to criteria pollutant inventories noted above (CARB, 2013d). For example, ROG emissions from off-road combustion are obtained from the criteria pollutant inventory described above, and speciation factors are applied to these ROG emissions estimates to estimate emissions of a given TAC chemical species (CARB, 2000).

TACs from regulated stationary sources are recorded in CARB datasets at the facility level (CARB, 2014j). Emissions data are reported to CARB from stationary facilities as part of the Air Toxics "Hot Spots" program (AB 2588, enacted 1987). Various criteria are used to determine whether a facility must report data to the CARB (CARB, 2013e; 2014j; 2014l), but a chief criterion is the manufacture, formulation, use, or release of any of 600 substances subject to the regulation. Reporting requirements differ by chemical species or

substance. Some species/substances require reporting only with regard to air emissions, while other species/substances are required to be reported if used or manufactured, regardless of estimated air emissions rate.

Facility-level TACs data are searchable by Standard Industrial Classification (SIC) code, air district, county, facility code, and chemical species. These facility-level data are further compiled by air districts, which publish annual reports summarizing emissions of TACs within each district from all sources (e.g., CARB, 2014k).

More recently, the South Coast Air Quality Management District (SCAQMD, or SC air district as above) passed legislation—Rule 1148.2—which requires reporting of use of potential TACs in oil and gas well stimulation (SCAQMD, 2013; PSR et al., 2014). This rule goes beyond existing TACs reporting requirements by specifically requiring reporting of the volume or mass of use of certain chemicals which are TACs, rather than reporting the estimated emissions rate.

In 2010, in the SJV air district, TACs of importance included (in order of mass rate of emissions): acetaldehyde, diesel PM, formaldehyde, and benzene (SJVAPCD, 2014). Mobile sources are responsible for over half of SJV TACs, while stationary sources were responsible for ~15% of emissions (SJVAPCD, 2014). Three of these four species are in the set of 10 indicator TACs species, and diesel PM is discussed further below.

Coverage of WS activities in CARB TAC inventory

Direct well-stimulation-related TAC emissions will occur in the upstream portion of the oil and gas industry. Key possible TACs impacts from well stimulation activities include:

- Release of hydrocarbons during the well completion ("flowback") process;
- Release or volatilization of components of the fracturing fluid, which could represent toxic hazards;
- Release of combustion byproducts or hydrocarbon (HC) fugitives from consumption of fuels during WS activities (e.g., by pumps, generators, compressors, or other on-site engines);

The above activities could result in TAC emissions from a mixture of point-source and mobile source emissions. To the extent that stationary sources associated with oil and gas report TAC emissions as part of AB 2588, these emissions will be included in the TAC inventory. Given the detailed source categories treated in the off-road mobile source inventory (noted above), it is likely that at least some mobile source TACs from well stimulation activities are counted in the current inventory.

It is not clear how emissions unique to well stimulation (e.g., emissions during fracturing fluid preparation, injection or flowback) are treated in current TAC inventory methods. No data exist in either the "hot spots" dataset or in the CTI to clearly differentiate well stimulation from non-well-stimulation oil and gas emissions.

Results of CARB TAC inventory

Results of the CTI for the most recent year (2010) are presented in Figure 3.3-8 and Figure 3.3-9 for the SJV and SC regions respectively. Tabular data are presented in Table 3.3-7 and Table 3.3-8 for the SJV and SC regions respectively.

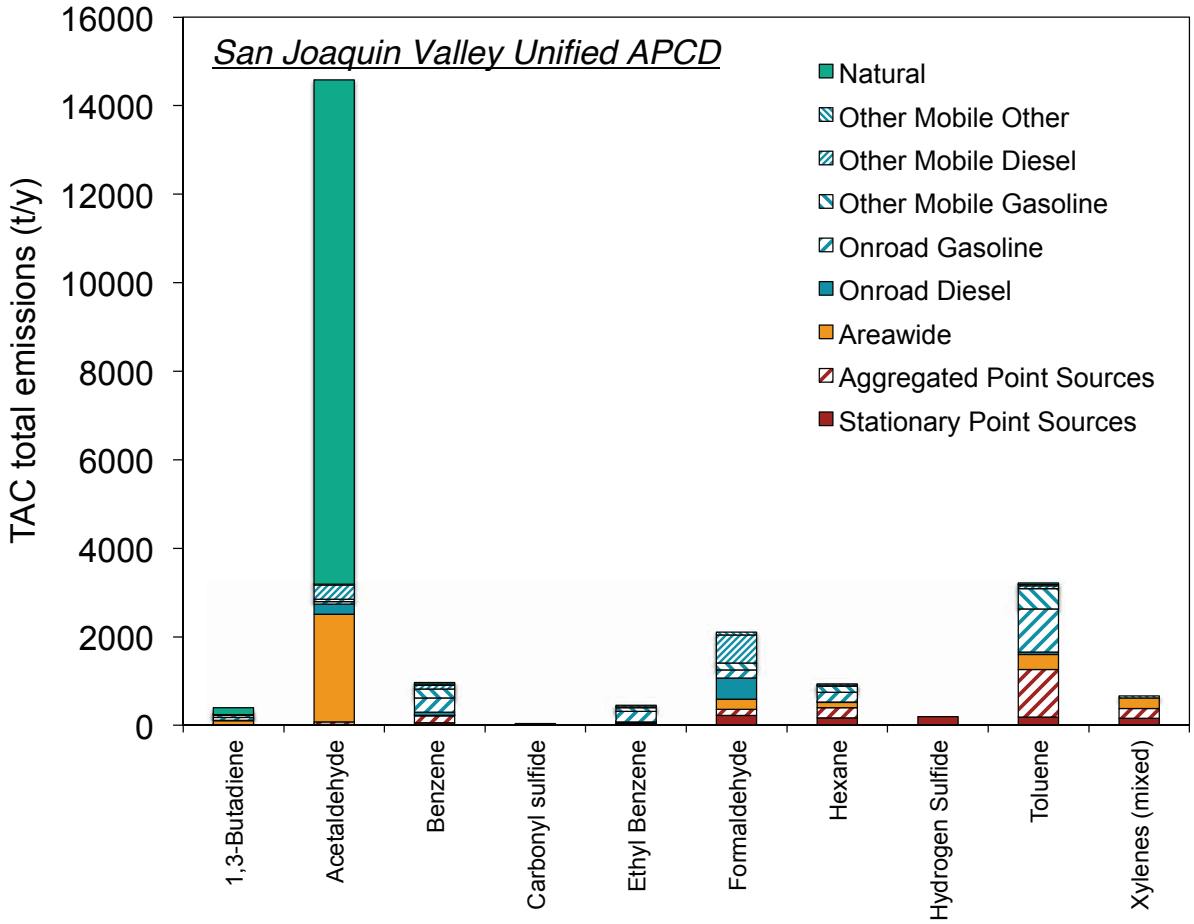


Figure 3.3-8. Total TACs releases for 10 indicator species in SJV region. Results for calendar year 2010, most recent available (CARB, 2013c). Emissions are in tonnes per year (1,000kg/y).

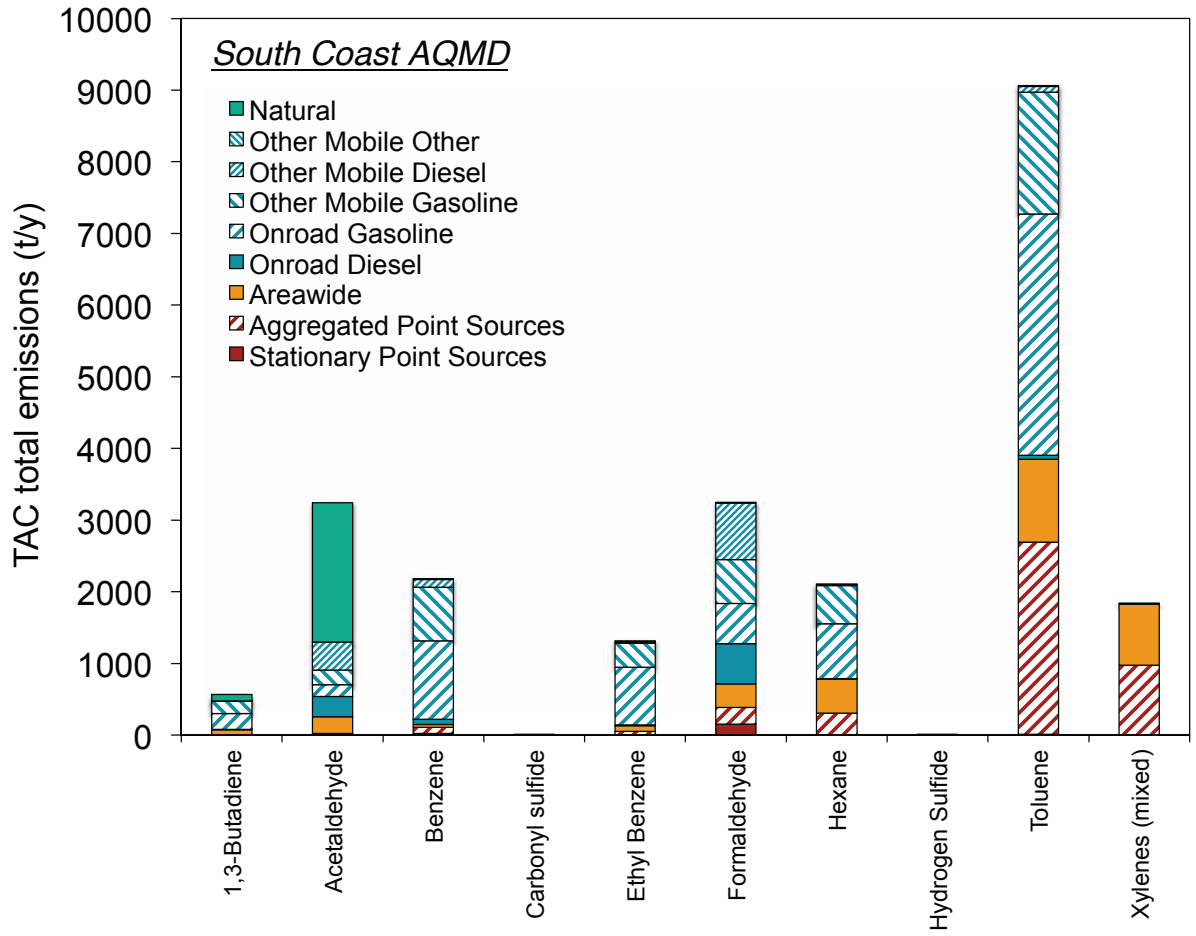


Figure 3.3-9. Total TACs releases for 10 indicator species in SC region. Results for calendar year 2010, most recent available (CARB, 2013c). Emissions are in tonnes per year (1,000kg/y).

Table 3.3-7. Overall toxics inventory results for indicator species in SJV region. Emissions are in tonnes per year (1,000kg/y). Results from 2010 calendar year (CARB, 2013c).

	Stationary Point Sources	Aggregated Point Sources	Area-wide	Onroad Diesel	Onroad Gasoline	Other Mobile Gasoline	Other Mobile Diesel	Other Mobile Other	Natural	Total	Fraction stationary point sources
1,3-Butadiene	0.4	1.4	105.9	6.1	67.3	44.5	8.2	10.3	150.9	395.0	0.1%
Acetaldehyde	20.4	53.3	2432.3	237.7	53.9	52.5	317.0	21.4	11395.1	14583.6	0.1%
Benzene	62.2	155.2	10.7	64.7	328.4	197.8	86.3	21.3	0.7	927.2	6.7%
Carbonyl sulfide	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0%
Ethyl benzene	19.9	24.3	26.3	10.0	232.4	88.1	13.4	6.1	0.0	420.5	4.7%
Formaldehyde	222.5	141.8	231.1	475.7	178.8	160.8	634.4	59.7	0.0	2104.7	10.6%
Hexane	168.5	229.1	120.3	5.2	221.9	143.1	6.9	3.3	0.0	898.3	18.8%
Hydrogen sulfide	193.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	193.8	100.0%
Toluene	189.9	1074.7	340.3	47.5	980.7	451.7	63.4	29.7	0.7	3178.6	6.0%
Xylenes (mixed)	161.7	216.0	244.8	0.0	0.0	0.0	0.0	0.0	0.0	622.5	26.0%

Table 3.3-8. Overall toxics inventory results for indicator species in SC region. Emissions are in tonnes per year (1,000kg/y). Results from 2010 calendar year (CARB, 2013c).

	Stationary Point Sources	Aggregated Point Sources	Area-wide	Onroad Diesel	Onroad Gasoline	Other Mobile Gasoline	Other Mobile Diesel	Other Mobile Other	Natural	Total	Fraction stationary
1,3-Butadiene	2.9	0.1	72.6	7.2	217.8	168.7	10.2	0.0	86.5	566.1	0.5%
Acetaldehyde	2.8	21.4	232.8	280.3	168.9	199.2	393.5	0.2	1944.2	3243.4	0.1%
Benzene	23.2	83.2	39.9	76.3	1092.7	747.8	107.1	1.4	0.0	2171.5	1.1%
Carbonyl sulfide	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	100.0%
Ethyl Benzene	3.6	46.3	81.8	11.8	806.0	333.3	16.6	0.1	0.0	1299.5	0.3%
Formaldehyde	152.4	231.6	328.7	561.0	563.3	609.9	787.6	5.5	0.0	3240.0	4.7%
Hexane	1.9	304.1	478.2	6.1	763.2	531.8	8.6	0.6	0.0	2094.6	0.1%
Hydrogen Sulfide	9.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3	100.0%
Toluene	10.0	2680.9	1160.0	56.1	3363.4	1701.3	78.7	1.0	0.0	9051.4	0.1%
Xylenes (mixed)	8.5	966.0	852.7	0.0	0.0	0.0	0.0	0.2	0.0	1827.5	0.5%

As can be seen from Table 3.3-7 and Table 3.3-8, key sources of the indicator TACs species in both SJV and SC region include vehicular sources (gasoline in particular) and aggregated (i.e., not individually reported) point sources. Some species (carbonyl sulfide and hydrogen sulfide) are emitted primarily or completely by stationary facilities. Facilities that report TACs emissions as part of the point-source reporting program are discussed in more detail below.

To the extent that oil and gas development contributes to overall diesel consumption (both on-road and off-road), some contribution of TACs from oil and gas activities in these categories is to be expected. Note that Figure 3.3-7 and the associated discussion suggest that the importance of ROGs from oil and gas related mobile sources is likely to be small. It is therefore likely that TACs from mobile source oil and gas activities are also small. However, no sector- or activity-level breakdown is available in the CTI TACs database as was available in the ROG database.

In contrast to the overall CTI results which cover all sources (stationary, areawide, mobile, natural), a much more detailed facility-level inventory is generated using reported data for facilities under the "Hot Spots" program, AB 2588. Using this data, it is possible to estimate TACs impacts of oil and gas activities from stationary source reporting facilities. In order to do this, the facility-level TACs databases were searched using Standard Industrial Classification (SIC) codes representing upstream oil and gas activities. Using OSHA (Occupational Safety and Health Administration) databases of SIC codes, 12 codes were determined to be related to oil and gas activities. Five of these codes are included in this report's estimates of upstream oil and gas activities (see Table 3.3-9).

It is not possible to separate these facility-level stationary-source TACs emissions by oilfield or pools. The reporting facilities to the TACs database do not line up with pools or fields as reported in DOGGR databases. Also TACs emissions source facilities in the database are sometimes very generally defined (e.g., "AERA Energy LLC, heavy oil production")

Table 3.3-9. SIC codes used in analysis of facility-level TAC emissions. Source: OSHA SIC database search for "petroleum" and "oil" (OSHA, 2014).

SIC code	Description	Included as upstream O&G?
1311	Crude petroleum and natural gas	Y
1321	Natural gas liquids	Y
1381	Drilling oil and gas wells	Y
1382	Oil and gas field exploration services	Y
1389	Oil and gas field services, not elsewhere classified	Y
2911	Petroleum refining	N
2922	Lubricants and greases	N
3533	Oil and gas machinery	N
4613	Refined petroleum pipelines	N
5172	Petroleum product wholesalers	N
5541	Gasoline stations	N
5983	Fuel oil dealers	N

Unlike the stationary source criteria pollutant inventory, no data source was found that separates TACs emissions by subsource (CARB, 2013c).

The distribution of facility-reported emissions for the 10 indicator species is shown in Figure 3.3-10 and Figure 3.3-11 for the SJV and SC regions, respectively. Tabular results are shown in Table 3.3-10 and Table 3.3-11 for SJV and SC regions. These values differentiate between emissions from the five SIC codes noted in the above table ("Y") and aggregate emissions from all other SIC codes. The five upstream oil and gas SIC codes noted in Table 3.3-9 are responsible for between 0% and 70% of the emissions of these species from stationary sources in the SJV air district. In the SC air district, these upstream stationary oil and gas sources were responsible for 0% to 10% of the emissions of these species from all stationary sources.

Because treatment of mobile source TACs in the CTI is derived from speciation of the criteria pollutant inventory, coverage of TACs from mobile sources associated with well stimulation or oil and gas activities will be subject to the same issues noted above. To recapitulate, a variety of mobile sources relevant to oil and gas (and presumably to well stimulation) activities are tracked, especially for off-road diesel equipment. However, it is not clear how to apportion these activities between conventional HC production and well stimulation activities without detailed study.

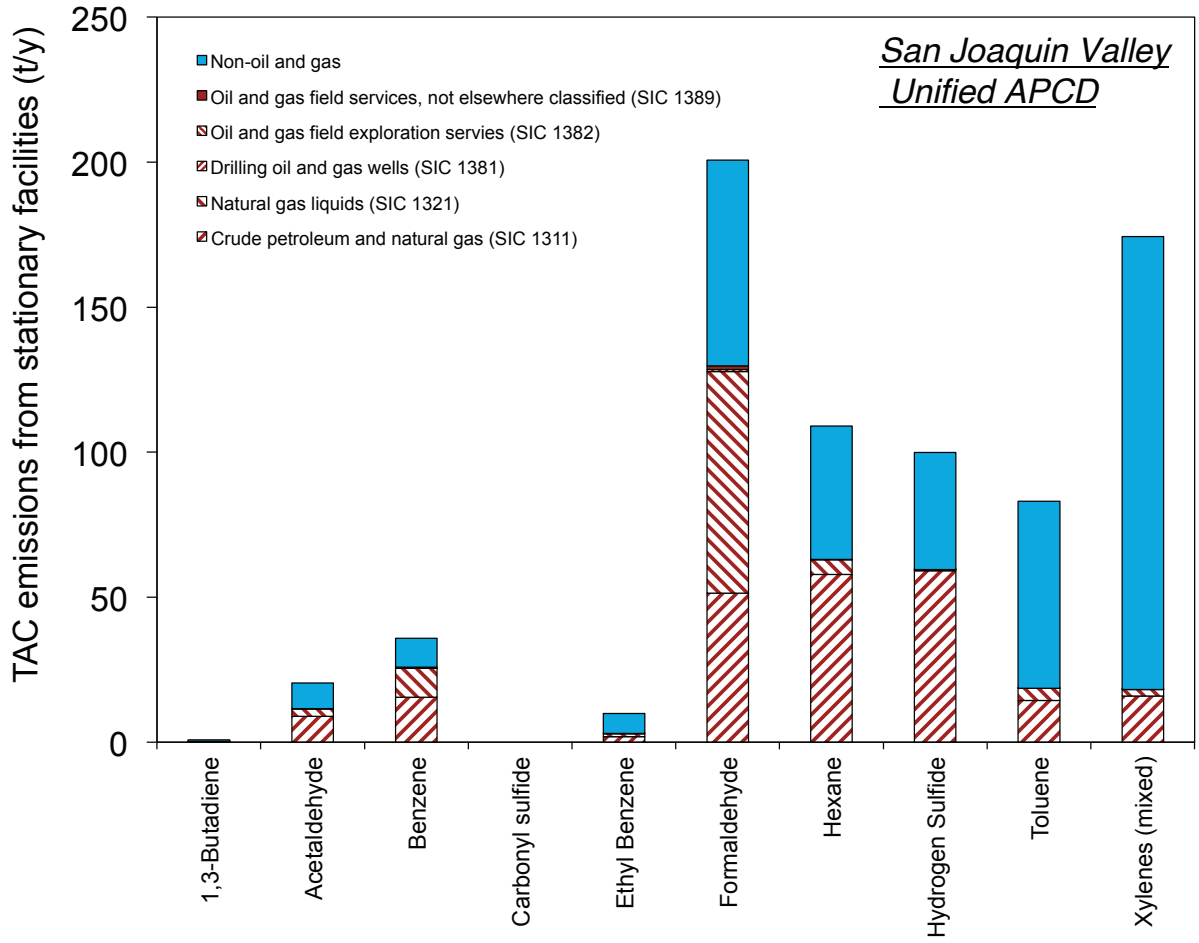


Figure 3.3-10. Summed facility-level TAC emissions in San Joaquin Valley (SJV) air district CARB, 2014j). Emissions plotted for indicator species for SIC codes 1311, 1321, 1381, 1382, and 1389. Facility-level emissions derived from CARB facility emissions tool. Total emissions are emissions from all SIC codes in the air district, including gasoline fueling stations.

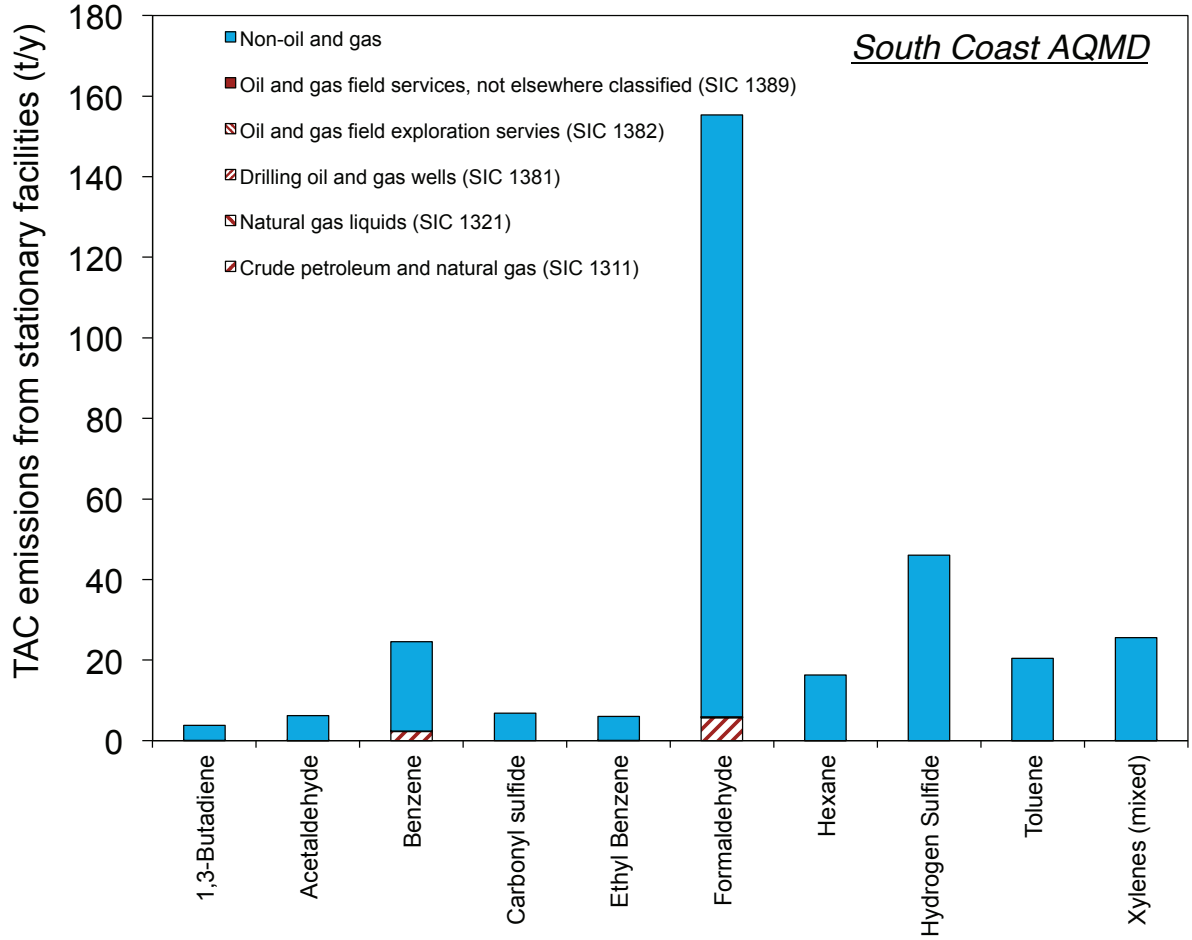


Figure 3.3-11. Summed facility-level TAC emissions in South Coast (SC) air district CARB, 2014j). Emissions plotted for indicator species for SIC codes 1311, 1321, 1381, 1382, and 1389. Facility-level emissions derived from CARB facility emissions tool. Total emissions are emissions from all SIC codes in the air district, including gasoline fueling stations.

Table 3.3-10. Emissions rates from stationary facilities in SJV region, as reported to facility-level reported TACs database (CARB, 2014j). Data from calendar year 2012. All emissions in tonnes per year (1,000kg/y).

	Crude petroleum and natural gas (SIC 1311)	**Natural gas liquids (SIC 1321)**	**Drilling oil and gas wells (SIC 1381)**	**Oil and gas field exploration services (SIC 1382)**	**Oil and gas field services, not elsewhere classified (SIC 1389)**	**Total oil and gas (SIC 1311-1389)**	**Non-oil and gas**	**Percentage oil and gas**
1,3-Butadiene	0.2	0.0	0.0	0.0	0.0	0.3	0.5	35.2%
Acetaldehyde	8.9	2.5	0.0	0.0	0.2	11.6	8.8	57.0%
Benzene	15.6	9.8	0.0	0.1	0.5	25.9	9.9	72.4%
Carbonyl sulfide	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Ethyl Benzene	1.9	1.0	0.0	0.0	0.2	3.1	6.8	31.2%
Formaldehyde	51.4	76.5	0.0	0.6	1.3	129.8	70.9	64.7%
Hexane	57.9	5.0	0.0	0.0	0.1	63.0	46.0	57.8%
Hydrogen Sulfide	59.2	0.3	0.0	0.0	0.1	59.5	40.3	59.6%
Toluene	14.4	4.2	0.0	0.0	0.1	18.6	64.4	22.4%
Xylenes (mixed)	15.9	2.3	0.0	0.0	0.0	18.2	156.1	10.4%

Table 3.3-11. Emissions rates from stationary facilities in SC region, as reported to facility-level reported TACs database (CARB, 2014j). Data from calendar year 2012. All emissions in tonnes per year (1,000kg/y).

	Crude petroleum and natural gas (SIC 1311)	**Natural gas liquids (SIC 1321)**	**Drilling oil and gas wells (SIC 1381)**	**Oil and gas field exploration services (SIC 1382)**	**Oil and gas field services, not elsewhere classified (SIC 1389)**	**Total oil and gas (SIC 1311-1389)**	**Non-oil and gas**	**Percentage oil and gas**
1,3-Butadiene	0.1	0.0	0.0	0.0	0.0	0.1	3.7	1.5%
Acetaldehyde	0.0	0.0	0.0	0.0	0.0	0.0	6.3	0.0%
Benzene	2.2	0.0	0.1	0.0	0.0	2.4	22.2	9.6%
Carbonyl sulfide	0.0	0.0	0.0	0.0	0.0	0.0	6.9	0.0%
Ethyl Benzene	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.5%
Formaldehyde	5.7	0.0	0.0	0.0	0.1	5.9	149.5	3.8%
Hexane	0.0	0.0	0.0	0.0	0.0	0.0	16.3	0.0%
Hydrogen Sulfide	0.0	0.0	0.0	0.0	0.0	0.0	46.0	0.0%
Toluene	0.0	0.0	0.0	0.0	0.0	0.0	20.4	0.0%
Xylenes (mixed)	0.0	0.0	0.0	0.0	0.0	0.0	25.6	0.0%

It does not appear possible to directly compare these two datasets. While the CTI (produced less frequently) reports emissions from "stationary point sources" that are in theory derived from the facility-level reporting explored above by SIC code, examination of the data for the 2010 year from both datasets shows discrepancies for all ten indicator species. For example, benzene emissions estimated by CTI datasets for the SJV region (defined as the San Joaquin Valley Unified APCD) in 2010 were 62.1 t/y for the category "stationary point sources." In contrast, querying the facility-level toxics database for 2010 for the same region, and summing resulting benzene emissions from all reporting facilities, results in total emissions of 38.6 t/y.

Given the above caveat, an approximate estimate of the relative importance of oil and gas stationary sources can be generated by comparing the upstream oil and gas facility level emissions (summed by SIC code as above) to the total CTI results for the same year. These results are shown in Table 3.3-12 and Table 3.3-13 below.

In summary, in the SJV region, upstream oil and gas point-source facilities are responsible for the great majority of H2S emissions (>70%) and are small contributors to emissions of benzene, formaldehyde, hexane and xylenes (1-10%). In the SC region, oil and gas sources are negligible contributors to emissions of our ten indicator TACs.

Note again that there will also be oil and gas mobile source TACs that are not accounted for in Table 3.3-12 and Table 3.3-13. Because oil and gas mobile sources are small contributors to both ROG and PM emissions (see Table 3.3-6), this is unlikely to affect the general results of this comparison.

Table 3.3-12. San Joaquin Valley oil and gas facility-reported emissions of ten indicator TACs compared to California Toxics Inventory estimates for all sources, both for year 2010. Emissions in tonnes (1,000 kg) per year.

SJVUAPCD	Total oil and gas (t/y, facility-level 2010)	Total all sources (t/y, CTI 2010)	Fraction
1,3-Butadiene	0.1	435.1	0.0%
Acetaldehyde	10.8	16061.2	0.1%
Benzene	24.2	1021.2	2.4%
Carbonyl sulfide	0.0	0.0	0.0%
Ethyl Benzene	2.3	463.1	0.5%
Formaldehyde	126.9	2318.0	5.5%
Hexane	47.2	989.3	4.8%
Hydrogen Sulfide	151.2	213.4	70.8%
Toluene	17.6	3500.7	0.5%
Xylenes (mixed)	17.6	685.6	2.6%

Table 3.3-13. South Coast oil and gas facility-reported emissions of ten indicator TACs compared to California Toxics Inventory estimates for all sources, both for year 2010. Emissions in tonnes (1,000 kg) per year.

SCAQMD	Total oil and gas (t/y, facility-level 2010)	Total all sources (t/y, CTI 2010)	Fraction
1,3-Butadiene	0.3	623.4	0.0%
Acetaldehyde	0.0	3572.1	0.0%
Benzene	2.3	2391.5	0.1%
Carbonyl sulfide	0.0	0.1	0.0%
Ethyl Benzene	0.0	1431.1	0.0%
Formaldehyde	8.5	3568.3	0.2%
Hexane	0.1	2306.8	0.0%
Hydrogen Sulfide	0.0	10.2	0.0%
Toluene	0.1	9968.5	0.0%
Xylenes (mixed)	0.1	2012.7	0.0%

3.3.2.2.4. SCAQMD Reporting of Hazardous Materials

The South Coast Air Quality Management District (SCAQMD, or SC region as above) recently approved regulation (Rule 1148.2), which requires the reporting of use of potentially hazardous materials in well stimulation, drilling, or workover activities. The chemicals which were reported in this regulation, as well as the average quantities injected or used, are tabulated in Table 3.3-14 and Table 3.3-15.

The SCAQMD database does not directly report masses of chemicals injected. For all operations reported in the SCAQMD database, the mass flow of each injected material (e.g., proppant) was reported, as well as the "maximum concentration" of a number of individual chemical constituents (e.g., proppant might be made of crystalline silica (max 95%) and phenol-formaldehyde resin (max 5%). These data are combined to determine a maximum injection rate for individual chemicals.

Table 3.3-14. TAC species associated with fracturing fluids extracted from SCAQMD dataset.

Toxic air contaminant	Average maximum kg injected per well
Crystalline Silica Quartz (SiO2)	67060
Phenol-Formaldehyde Resin	16369
Methanol	1619
Hydrogen Chloride	622
Ethylene Glycol	443
Hydrofluoric Acid	45
2-Butoxy Ethanol	37
Hexamethylene Tetramine	33
Sodium Hydroxide	31
Silica Fumed	2
Cristobalite (SiO2)	1

Table 3.3-15. TAC species associated in matrix acidizing extracted from SCAQMD dataset.

Toxic air contaminant	Average max. mass injected (kg)
Crystalline Silica (Quartz)	3546
Hydrocholoric Acid	1058
Phosphonic Acid	406
Aminotriacetic Acid	309
Xylene	207
Hydrofluoric Acid	179
2-Butoxy Ethanol	213
Ethylbenzene	63
Methanol	34
Thiourea Polymer	15
Isopropanol	13
Sulfuric Acid Ammonium Salt (1:2)	7
Acrylic Polymer	7
Toluene	4
1,2,4 Trimethylbenzene	2
Diethylene Glycol	1
Ethylene Glycol	1
Naphthalene	1
Cumene	<1

These reported chemicals are not universally present in Clean Air Act lists of TACs, but their usage is required to be reported by SCAQMD. Also, the list of chemicals reported to SCAQMD may differ from other lists of potential toxics noted elsewhere in this report.

Additives and components of fracturing fluids could potentially be released to the air during mixing and preparation, injection, or flowback of fracturing fluids. The volatility of each of the additives can vary. For example, the largest mass additive is crystalline silica quartz (proppant). This proppant is not generally volatile, and only the proppant fines are of a concern from an air quality perspective.

3.3.2.2.5. Naturally Occurring Radioactive Materials

One possible concern about hydraulic fracturing is the release of naturally occurring radioactive materials (NORM). NORM can result in contamination of water with radioactive species, as well as result in air impacts through liberation of species that can enter gaseous phase (e.g. radon).

Though NORM is a serious concern for some shale formations (in particular the Marcellus formation of Pennsylvania, where it poses serious water quality issues), it is seen as less concerning in California (U.S. EPA, 2015).

California does contain deposits of radioactive elements in Kern County (USGS, 1954; USGS, 1960). However, these deposits are found to the south and east of the Kern County oilfields (USGS,1954; USGS, 1960). EPA studies suggest that well fluids and oilfield equipment in California are not significantly affected by radioactive species (U.S. EPA, 2015).

3.3.2.2.6. CARB Inventories for PM emissions

As with the above-described ROG and NO_x inventories, CARB criteria pollutant inventories track PM emissions of various classifications from both stationary and mobile sources.

CARB PM inventory methods

The CARB criteria pollutant inventory also estimates emissions of total particulate matter (PM) as well as PM10 and PM2.5.

The stationary source PM inventory is performed using the same classification and categorization scheme noted above for the stationary source ROG and NO_x inventories. See discussion above for details of stationary source inventory construction and categorization.

The mobile source PM inventory is performed using the same classification and categorization scheme noted above for the mobile source ROG and NO_x inventories. As noted above, on-road mobile source emissions are not clearly differentiated into oil

and gas-associated emissions sources. Off-road mobile source emissions have a detailed classification for oilfield equipment (see above).

Total PM emissions estimated for a given source are partitioned into PM size bins using a set of standard PM speciation factors for ~500 stationary sources, mobile sources, or industrial/agricultural activities (CARB, 2014m). Oil and gas-specific PM size data are not available, but data are available for multiple categories of off-road diesel vehicles, which will comprise the majority of well-stimulation-site emissions of PM. These emissions are differentiated by type of vehicle and vehicle age (CARB, 2014m). Given that oil and gas- or well-stimulation-specific PM will often be emitted from processes similar to those used across industries (e.g., heavy diesel equipment), the use of non-oil and gas-specific PM speciation factors is a reasonable approach.

Coverage of WS activities in CARB PM inventory

Coverage and scope of well-stimulation-associated PM emissions in the CARB PM inventory should be identical to coverage and scope noted above for the ROG and NO_x inventories, because the inventory structure is similar.

Results of CARB PM inventory

Oil and gas stationary sources in the SJV region are responsible for 1.9 t per day of total PM and a nearly identical amount of PM2.5 (see Figure 3.3-12). This amounts to 0.4% of stationary anthropogenic emissions of total PM and 2.7% of stationary anthropogenic emissions of PM2.5. In the SC region, total stationary oil and gas-related sources of PM and PM2.5 equal 0.04% of stationary anthropogenic emissions of total PM and 0.13% of stationary anthropogenic emissions of PM2.5 in the SC region.

In the SJV region, oil and gas off-road sources are responsible for 0.2 and 0.18 t per day of total PM and PM2.5, respectively (see Figure 3.3-13). These equal 1.4% and 1.6% of the mobile-source PM in the SJV. However, due to large area-wide sources of PM in the SJV, off-road oil and gas sources are only responsible for 0.04% of total PM and 0.26% of PM2.5. In the SC region, off-road oil and gas sources emit some 0.03 t per day of PM and PM2.5 (see Figure 3.3-13). This represents ~0.3% of total mobile-source PM and 0.01% of total PM from all sources.

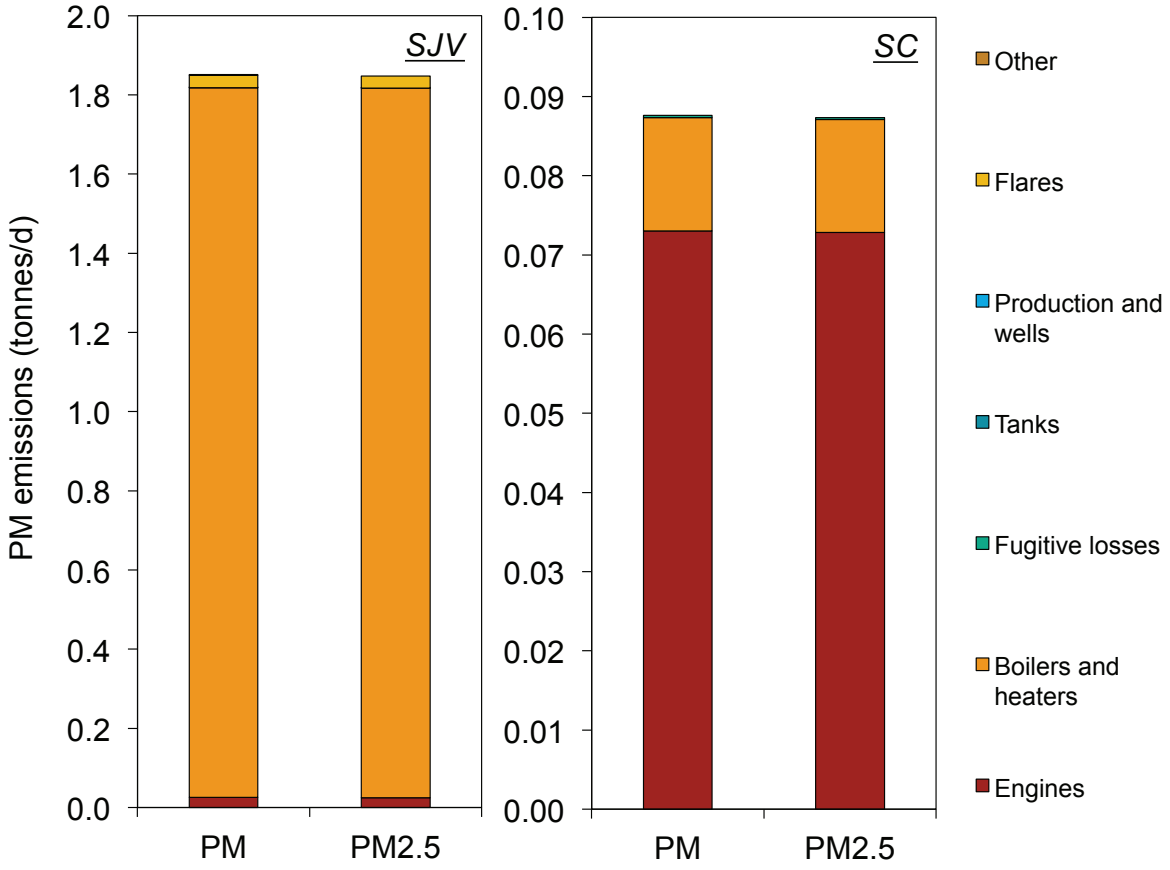


Figure 3.3-12. 2012 stationary source emissions of total particulate matter (PM) and particulate matter of less than 2.5 micrometer (PM2.5) from all oil and gas production sources in San Joaquin Valley and South Coast air districts. Source: CARB (2013b).

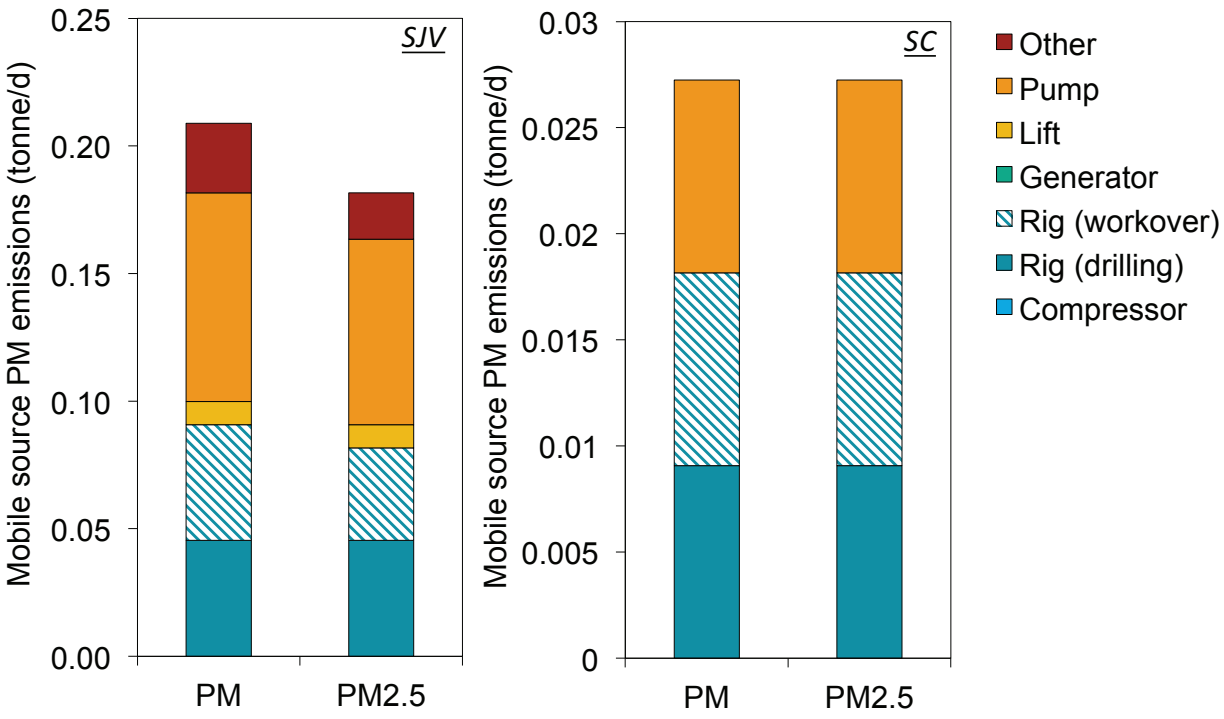


Figure 3.3-13. 2012 off-road mobile source emissions of total particulate matter (PM) and particulate matter of less than 2.5 micrometer (PM2.5) from all oil and gas production sources in San Joaquin Valley and South Coast air districts. Source: CARB (2013b).

3.3.2.2.7. CARB Inventories of Dust Emissions in Rural Regions

A major concern for air quality in rural California is the presence of dust from agricultural activities and other industrial activities occurring on non-paved surfaces. Dust is of particular concern in the SJV, where it contributes to the high levels of PM found in SJV air. If well stimulation technologies significantly affected regional dust levels, this could be an important air quality impact.

CARB creates inventories of dust emissions as part of their criteria pollutant inventory, adding dust emissions from all sources to PM, PM10, and PM2.5 totals. The breakdown of PM from dust sources, as compared to all sources of PM in the SJV region is shown in Table 3.3-16. All dust sources contribute a total of 86% of total PM and 41% of PM2.5 in the SJV (CARB, 2013b). Natural background dust sources are not included in the inventory (CARB, 2013b) and are likely difficult to determine, given the large extent of landscape modification undertaken in the SJV.

Most of the dust sources in the SJV region are farming related. Oil and gas operations could contribute to a variety of categories, including: “Construction and demolition - Building and construction dust: Industrial”, “Construction and demolition – Road construction dust”, “Fugitive windblown dust - Dust from unpaved roads and associated areas”, “Unpaved road travel dust – city and county roads” and “Unpaved traffic area - Private”. These sources contribute a total of 24% of total PM and 24% of PM2.5. It is unclear in general how important oil and gas sources are in these inventory categories.

The San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) has developed methods for assessing dust emissions in more detail than other air districts. For unpaved, non-farm roads, a simple methodology is used that computes emissions based on an assumed number of trips per day on each mile of unpaved county and other non-farm road (CARB, 2004a). No specification is made about how the oil and gas industry might contribute to these trip loads (CARB, 2004a). For unpaved private roads, a simple scaling of the above results is performed (CARB, 2004b), assuming one-tenth the travel seen on county and other public unpaved roads. For the “Unpaved traffic area – Private” source category, a method was developed by SJVUAPCD to include sources such as farms, mines, landfills, and oil and gas operations (CARB, 2003). The emphasis in this dataset is on parking lots, working areas, and other cleared land that is driven on. The results of these methods are shown in Table 3.3-17 for the year in which the methodology was developed. As can be seen, the oil and gas industry contributes to a small fraction (0.6%) of the unpaved road dust emissions in the SJV region, with farms dominating emissions again.

While exact quantification is not possible, these results suggest that farming is the major source of anthropogenic dust in the San Joaquin Valley, and that oil and gas is a minor contributor.

Table 3.3-16. Dust emissions contribution to overall PM emissions in the SJV region (CARB, 2013b). Emissions in tonnes per day (1,000kg/d).

	PM	PM10	PM2_5
Farming operations	155.6	70.7	10.6
Fugitive windblown dust	87.5	40.3	6.9
Paved road dust	68.6	31.4	4.7
Unpaved road dust	57.2	37.6	3.8
Other dust	17.5	8.6	0.9
Total dust	386.4	188.5	26.8
All PM sources	479.8	255.7	68.7

Table 3.3-17. PM10 from dust emissions from unpaved traffic areas (non-road), tonnes per year (1,000kg/y). (CARB, 2003).

	PM 10	%
Farms	2073.0	86.1%
Cotton processing	31.8	1.3%
Landfills	217.9	9.1%
Mining	37.2	1.5%
Oil drilling	14.3	0.6%
Construction	32.7	1.4%

3.3.2.2.8. Natural Sources of Hydrocarbon-Related Air Emissions (Geologic Seeps)

Hydrocarbon species can be emitted to the air from natural sources by surface expressions of hydrocarbon materials (e.g., tar pits) or geologic conduits, fractures, or fissures connecting hydrocarbon-containing reservoirs or sediments to the surface. This possible source is particularly important in the SJV and SC regions, where large oil and gas deposits exist. Because of the co-location of hydrocarbon seeps and oil and gas activities, this has been noted as a potential confounding factor in attributing atmospheric observations to oil and gas activities (e.g., see Wennberg et al., 2012 or Peischl et al., 2013).

The CARB criteria pollutant inventory indicates that petroleum seeps were responsible for 20.0 t per day of ROG out of a total of 6354 t per day across California from all sources (natural and anthropogenic). This can also be compared to 1579 tons per day of ROG from anthropogenic sources. CARB estimates that the vast majority of these ROG emissions are emitted in the South Central Coast Air Basin from offshore seeps in the Santa Barbara region (CARB, 1993).

3.3.2.2.9. Summary of CARB Inventories Treatment of WS Activities

A number of general conclusions can be drawn from the above discussion:

1. Oil and gas activities are responsible for small (generally <5%) fractions of GHG, VOC and PM emissions to California air basins where oil and gas activities are concentrated.

2. Oil and gas activities are responsible for small fractions of NO_x emissions in regions of significant oil and gas activities (<10%)

3. Oil and gas activities are responsible for significant fractions of SO_x emissions in the SJV region (~30%)

4. Oil and gas activities are responsible for significant fractions (30%-70%+) of some stationary source TAC emissions in the SJV (see Figure 3.3-10). Because of large mobile sources and dispersed sources of our indicator TACs, fractions of overall TACs contributions are smaller (see Table 3.3-12).

5. Oil and gas activities appear responsible for large fractions of total hydrogen sulfide and hexane emissions in the SJV region.

6. While dust is a major air quality concern in the SJV region, all evidence points to oil and gas sources being a minor contributor to overall anthropogenic dust emissions and PM from dust.

7. Current inventory methods do not generally allow for clear differentiation of well stimulation from non-well-stimulation oil and gas activities. Better understanding of sources for emissions (e.g., produced hydrocarbon release, processing, other ancillary processes) would allow for further differentiation between stimulation and non-stimulation sources.

8. In some categories (e.g., off-road mobile source), evidence points to some coverage of well-stimulation-related emissions sources, although the exact coverage of well-stimulation-related emissions cannot be determined from the inventory.

9. For some category/pollutant combinations (e.g., crystalline silica dust), coverage of the well-stimulation-associated emissions is unclear or uncertain.

10. Given the relatively small contributions of overall oil and gas activities to most pollutant inventories, treatment of well stimulation emissions is not likely to result in significant changes to larger-scale inventories (e.g., regional or state level).

11. Given the major contribution of overall oil and gas activities to emissions of some stationary TACs in the SJV, application of well stimulation technologies could significantly affect emissions of these TACs, either directly during well stimulation activities or indirectly due to increased production.

3.3.2.3. State-Level Industry Surveys Produced by the California Air Resources Board (CARB)

In 2009, CARB began a detailed survey of oil and gas producer emissions. This survey covers the year 2007, and was released in 2011. As the survey results were further analyzed, corrections were performed and the current version of the results is presented in the revised version of October 2013 (Detwiler, 2013).

3.3.2.3.1. Survey Methods

In early 2009, a survey was mailed to 325 companies representing 1,600 oil and gas facilities. These facilities represented ~97% of the 2007 oil and gas production in California (Detwiler, 2013). The results of the survey were used to compute emissions of CO_2eq. GHGs.

The survey coverage was designed to include all upstream, transport, and refining processes in California. Production and processing activities included all activities required to lift oil and gas to the surface, process it (e.g., acid gas removal), and prepare it for transport to refineries. Oil and gas extraction facilities were included in the survey (Detwiler, 2013, p. 1-3) as were drilling and workover companies (Detwiler, 2013, p. 1-4). In addition, companies that perform ancillary services such as produced water disposal were also included (Detwiler, 2013, p. 1-4). It is not clear if specialized oilfield services involved in well stimulation (e.g., companies that only perform hydraulic fracturing services as subcontractors) were included in the survey coverage.

Related to well stimulation activities, companies were required to report number of active wells, well cellars, and well-maintenance activities (Detwiler, 2013, p. 4-1). By CARB definitions, hydraulic fracturing is considered a well-maintenance activity (Detwiler, 2013, p. 4-1), so results from fracturing should be included in survey results. No discussion of acid fracturing or matrix acidization is explicitly included in the survey, although companies may have reported such activities under "well maintenance" or "well workover."

Of particular importance is the fact that this survey is significantly more detailed in coverage, scope, and specificity than the above-described inventory methods. The survey consists of 16 tables, with very specific required reporting (e.g., presence of access hatch or pressure relief valve on tank) (Detwiler, 2013, p. A-20). Other examples include nearly 30 types of pumps listed in survey appendices (Detwiler, 2013, p. D-4) and dozens of types of separators included in survey definitions (Detwiler, 2013, p. E-3). The calculation methods for determining emissions rates from reported data are included in a detailed methodological appendix.

3.3.2.3.2. Survey Results

The survey found CO_2eq. GHG emissions from the oil and gas industry to be 17.7 Mt CO_2eq. in 2007. This figure does not include refinery emissions, so results should be equivalent to the above GHG inventory result. The emissions are partitioned by type and gas, as shown below in Table 3.3-18. The emissions are partitioned by industry segment as shown in Table 3.3-19. Emissions by air district are reproduced below in Table 3.3-20.

The survey also reports emissions broken down by type of equipment. The most important emissions sources in the inventory were found to be as follows (all sources greater than

10% of total emissions presented): steam generators (41%), combined heat and power systems (22%) and turbines (17%) (Table 3-6 of Detwiler, 2013). Vented emissions came primarily from automated control devices (31%), compressor blowdowns (17%), natural gas gathering lines (14%), gas sweetening and acid gas removal (13%), well workovers (11%) and gas dehydrators (11%). Fugitive emissions came primarily from compressor seals (42%) and storage tanks (27%).

Table 3.3-18. Results from CARB 2007 oil and gas industry survey. Reproduced from Detwiler (2013), Table 3-1.

Type of source	Gas	Emission (kt/y)	Emission of CO_2 eq.
Combustion	CO_2	16073.4	16398.3
	CH_4	10.8	
	NO_x	0.3	
Venting	CO_2	56.0	392.6
	CH_4	16.0	
	NO_x	0.0	
Fugitive	CO_2	107.3	895.5
	CH_4	37.5	
	NO_x	0.0	

Table 3.3-19. Results from CARB 2007 oil and gas industry survey, presented by business type. Reproduced from Detwiler (2013), Table 3-2.

Type of source	Gas	Emission (kt/y)
Onshore crude production	CO_2eq.	10343.1
Natural gas processing	CO_2eq.	1043.4
Onshore natural gas production	CO_2eq.	547.6
Crude processing and storage	CO_2eq.	407.2
Natural gas storage	CO_2eq.	334.8
Offshore crude production	CO_2eq.	140.1
Crude pipelines	CO_2eq.	89.8
Other	CO_2eq.	4764.7

Table 3.3-20. Results from CARB 2007 oil and gas industry survey, presented by air district. Reproduced from Detwiler (2013), Table 3-4.

Air district	Gas	Emission (kt/y)
San Joaquin Valley	CO_2eq.	14,006
South Coast	CO_2eq.	1,205
Santa Barbara County	CO_2eq.	1,049
Monterey Bay Unified	CO_2eq.	498
Ventura County	CO_2eq.	265
Other	CO_2eq.	636
Total	CO_2eq.	17,659

3.3.2.3.3. Survey Alignment with other California Inventories

The above reported total emissions figure of 17.7 Mt CO_2eq. is slightly higher than the reported inventory value of 17.0 Mt CO_2eq. reported in the 2014 inventory for the year 2007 (CARB, 2014d). A disparity of <5% between these two estimates is consistent with differences that would occur due to methodological differences between the two fundamentally different studies (survey vs. inventory).

In the 2014 GHG inventory, estimated fuel combustion emissions of CO_2, CH_4, and N_2O totaled 15.767 Mt CO_2eq, or 92.7% of the total inventory. In the CARB survey, combustion emissions are responsible for 93% of the total inventory emissions (Detwiler, 2013, p. 3-1). In terms of emissions per gas, the GHG inventory reports 94% of total emissions (combustion + fugitive/venting) as CO_2, with the remainder from CH_4 and N_2O. In contrast, the survey estimates 91.8% of statewide oil and gas emissions as CO_2. Alignment in these sub-results between two different methodologies (e.g., industry survey vs. inventory) increases the confidence in these results.

The yearly GHG inventory is created at the state level, which does not allow for comparison of the emissions by air district reported in Table 3.3-20. Because the GHG inventory does not report emissions by source technology (e.g., steam generator), no comparison between the survey and the inventory at the technology level can be performed. In summary, there is generally very good agreement between the CARB GHG inventory (2014 version) and the CARB oil and gas emissions survey. Such alignment increases the confidence that GHG emissions from the oil and gas industry in California are well understood.

3.3.2.4. Federal Emissions Inventories

While the chief focus of this report is on California information sources, some U.S. federal data are also available on California oil and gas operations.

The U.S. EPA GHG reporting program (U.S. EPA GHGRP) is an annual facility-level-reported inventory for GHG emissions. The requirement for reporting emissions is currently set at 25,000 tonnes per year CO_2eq., and the facilities are separated by industry and state starting in 2008 (U.S. EPA, 2010). This is unlike the national GHG emissions inventory, which is an inventory of GHG emissions from oil and gas production aggregated by activity. The GHG inventory is constructed using standard emissions factors combined with activity counts across the national oil industry. This is compared to the GHGRP, where producers report emissions directly to U.S. EPA.

Within the U.S. EPA GHGRP, the specific section relating to the oil and gas sector is Subpart W, which covers all emissions from the well to the refinery gate. Each operator reports emissions for a facility, which is defined by Subpart W as all emissions associated with wells owned by a single operator, in a producing basin. Reported emissions are computed through a combination of direct measurement, mass balance, and emission factors. Most venting and fugitive emissions are based upon "engineering estimations," which primarily utilize default emissions factors as a function of activity (U.S. EPA, 2010).

The emissions reported the GHGRP are aggregated over twenty categories (see Table 3.3-21). Emissions are reported by species (typically CO_2, N_2O, or CH_4). The data also report specific information about the equipment utilized on site (e.g., whether a vapor recovery system is used for atmospheric storage tanks). For most operators, emissions are reported for only a few of these categories. There is a designation for emissions that occur during well completions from hydraulic fracturing of gas wells. However, since well stimulation in California is utilized primarily for oil production, no well-stimulation-related emissions are reported in the GHGRP for California producing basins.

Table 3.3-21. Emissions reporting categories for GHGRP subpart W, reproduced from the FLIGHT tool (U.S. EPA, 2015b).

Natural gas pneumatic devices	**Associated gas venting and flaring**
Natural gas driven pneumatic pumps	Flare stacks
Acid gas removal units	Centrifugal compressors
Dehydrators	Reciprocating compressors
Well venting for liquids unloading	Other emissions from equipment leaks estimated using emission factors
Gas well completions and workovers	Local distribution companies
Blowdown vent stacks	Enhanced oil recovery injection pump blowdown
Gas from produced oil sent to Atmospheric tanks	Enhanced oil recovery hydrocarbon liquids dissolved CO_2
Transmission tanks	Onshore petroleum and natural gas production and distribution combustion emissions
Well testing venting and flaring	Offshore sources

Due to the 25,000 tonnes per year requirement, emissions from small oil and gas production will likely be undercounted. This is demonstrated in Table 3.3-22, which shows reported GHG emissions for California oil operations separated by basin and source of emissions. Note that these emissions are significantly below those reported by operators in the California oil and gas survey discussed above. For example, compare the results for the San Joaquin production basin from which GHGRP emissions are reported as ~2,050 kt/y CO_2eq., while California survey emissions are reported as ~14,000 kt/y CO_2eq (see Table 3.3-20).

Table 3.3-22. Results from GHGRP subpart W, presented by production basin for California. Reproduced from FLIGHT tool (U.S. EPA, 2015b).

	Reported GHG emissions (kt CO_2eq/y)						
Basin	**Combustion**	**Pneumatics**	**Venting & Flaring**	**Tanks**	**Compressors**	**Other**	**Total**
San Joaquin	1924	18	56	13	18	19	2048
Los Angeles	220	0	2	2	0	0	224
Offshore	235	0	4	0	0	35	274
Other	125	79	5	24	4	40	277

3.3.2.5. Emissions From Silica Mining

One example of an offsite impact of concern is crystalline silica dust emissions during mining and processing of proppant. Crystalline silica dust is a TAC, and can affect human health. Silica dust can be created during the proppant mining, production, and usage phases. Silica is a topic of concern as a WST occupational hazard; for example, see work by Esswein et al. (2013) for exposure assessment in locations outside of California. No oil-and-gas-associated SIC codes in the SJV or SC air districts reported emissions of silica dust. In the SJV air district in total, facility-level total emissions of crystalline silica (CARB species ID 1175) equaled ~749,000 lbs, with a total of 85 facilities reporting from a variety of SIC codes. Similar values are reported for total crystalline silica emissions in the CTI database for 2010 in the SJV region. However, none of the five upstream (or 12 total) SIC codes associated with oil and gas report emission of crystalline silica. In the SJV air district, key SIC codes reporting silica emissions are as follows: construction sand and aggregate (SIC 1442); nonmetallic minerals (SIC 1499); asphalt paving mixtures (SIC 2951); and minerals, ground or treated (SIC 3295). It is not clear from public documents if any of the above facilities are supplying proppant materials for well stimulation activities, and therefore if they may be considered a well-stimulation-related emissions source.

3.3.3. Potentially Impacted California Air Basins

While GHGs have impacts on global climate, the other three well-stimulation-related emissions (VOC/NO_x, TACs and PM) are relatively short-lived and primarily influence the air basins where oil and gas extractions occur. According to the Department of Oil Gas and Geothermal Resources (Figure 3.3-14), the two largest California oil and gas producing regions are contained within the San Joaquin Valley (SJV) Unified air district and South Coast (SC) air district. Specifically, significant oil production occurs in the Kern, Santa Barbara, and Ventura air districts, while non-associated (dry) natural gas production occurs in a number of Northern SJV air districts.

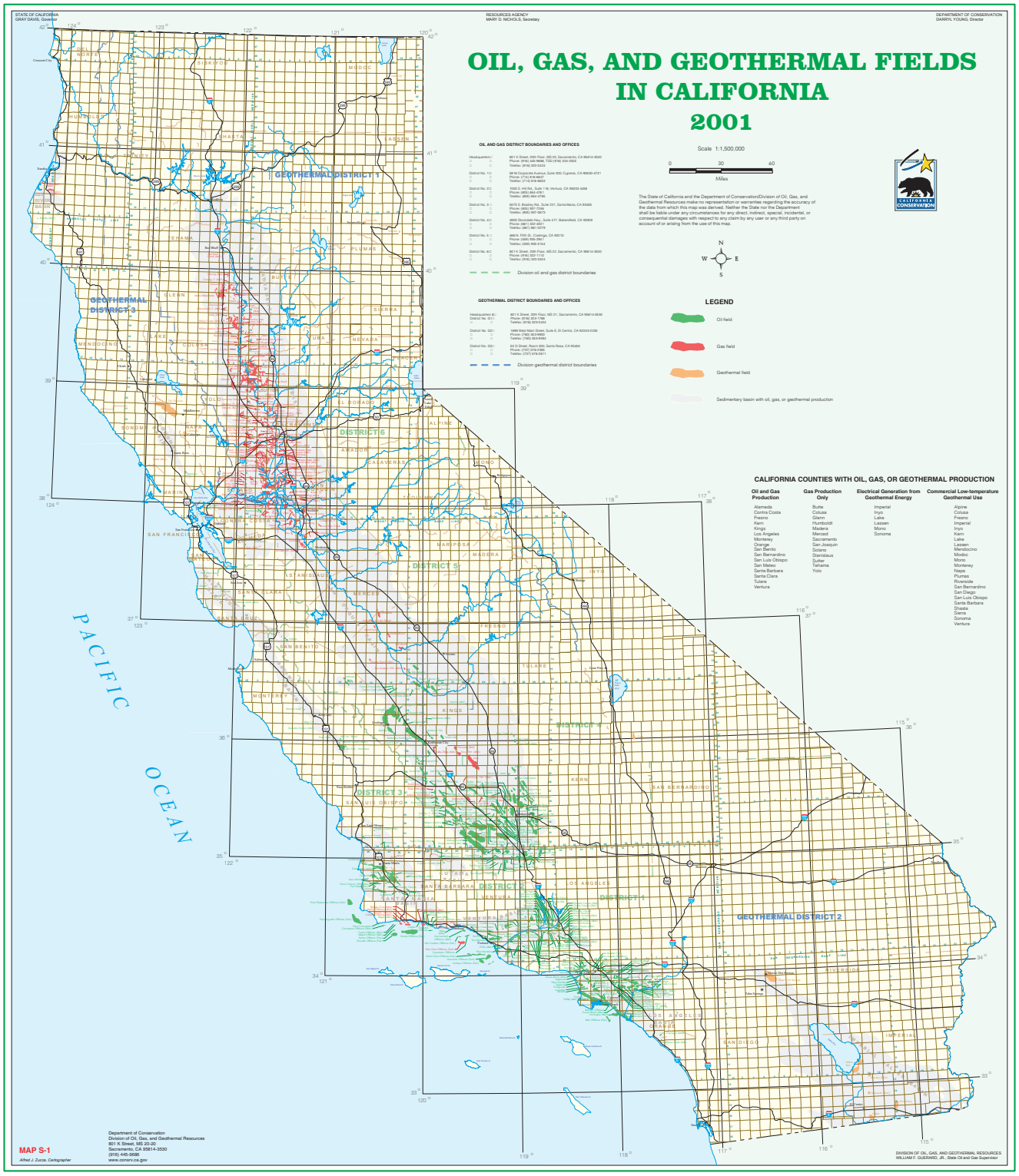


Figure 3.3-14. Map of oil (green) and gas (red) fields in California. Image courtesy of California Department of Oil, Gas and Geothermal Resources [DOGGR] http://www.conservation.ca.gov/dog/Pages/Index.aspx.

3.3.3.1. Status And Compliance in Regions of Concern

The two air basins (San Joaquin Valley and South Coast) most strongly impacted by oil and gas production also coincide with the worst air quality in California. Both air basins are currently out of compliance with both national ozone and PM2.5 standards.

Figure 3.3-15 shows the current designation of ozone attainment status of air districts in California. Ozone pollution level is characterized by a "design value," a three-year rolling average of the fourth highest 8-hour ozone concentrations measured at the monitoring station. The designation of attainment status is determined by comparing the design value to the National Ambient Air Quality Standard. The nonattainment areas are further divided into six classes from "marginal" to "extreme" depending on the extent to which the design value exceeds the standard. Both San Joaquin Valley and South Coast are classified as an "extreme" nonattainment area, meaning their design values are greater than 175 ppb, which is more than double the current 8-hour ozone standard (75 ppb) and almost three times EPA's proposed update to the standard (65 ppb). The Sacramento air district, located in the dry gas producing region, is also a "severe" nonattainment area for ozone (Figure 3.3-15).

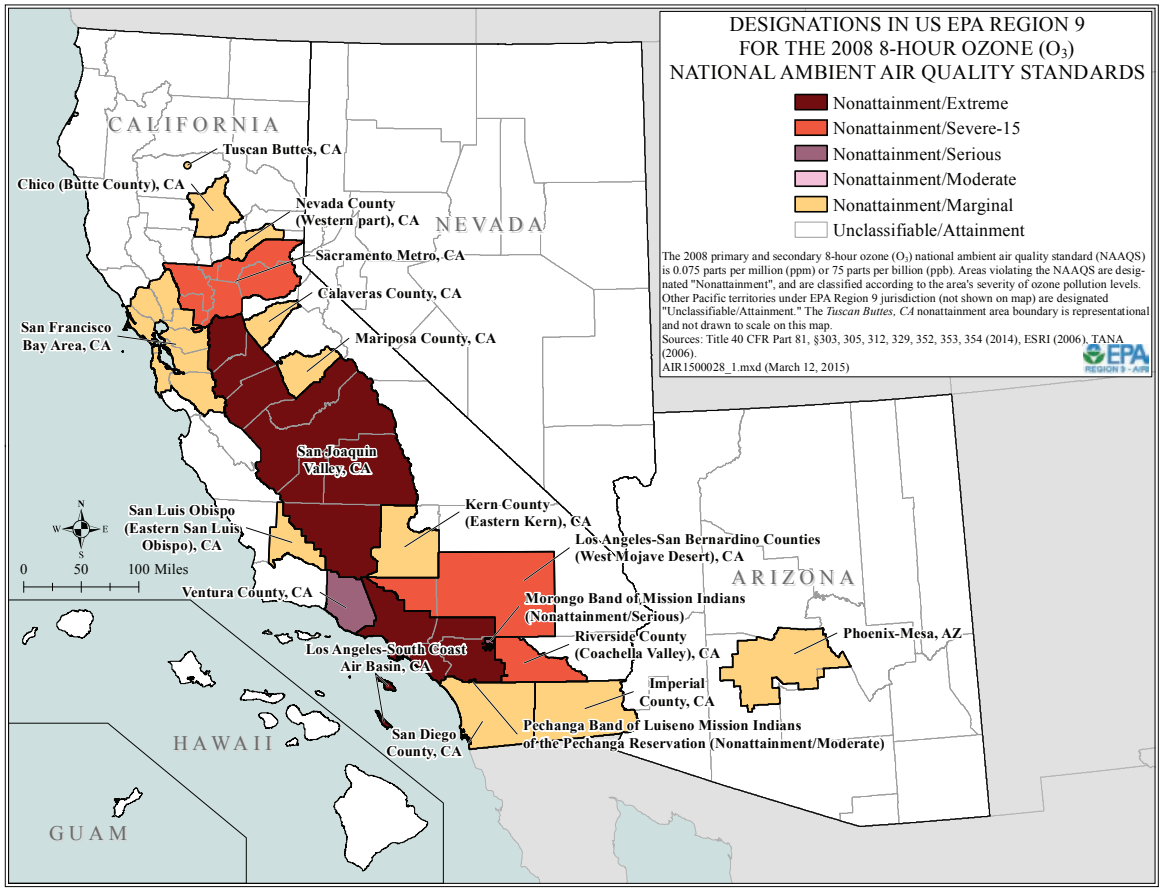


Figure 3.3-15. Air basin designation of 2008 8-hour ozone standard. Source: U.S. EPA, 2012.

The majority of the counties within the SJV and SC air basins are out of compliance with the 24-hour PM2.5 standard (35 mg/m^3), and a few with the newly established annual PM2.5 standard (12 mg/m^3) (Table 3.3-23). Sacramento is a nonattainment area for the 24-hour PM2.5 standard, but not for the annual standard.

A number of factors result in the poor air quality in the SJV and SC regions. First, unfavorable topography creates local circulations trapping emissions in the air basins. Second, besides the oil and gas industry, both regions host diverse emission sources including industry, agriculture, residential homes, businesses, and the transport sector. The SJV is among the nation's largest agriculture areas, with emissions from dairy farms contributing to fine particle formation. Los Angeles County is the most populated county in the U.S. (U.S. Census, 2010) resulting in significant air emissions. Third, the generally warm and sunny conditions in the state promote photochemical reactions and formation of smog in the summer. Cool and humid conditions in winter promote fine particulate formation in the winter.

Table 3.3-23. Attainment status for PM2.5 in the main oil and gas producing regions. (Source: U.S. EPA, 2009 and CARB, 2013f)

Area name	Counties exceeding 24-h PM2.5 standard (35 ug/m^3)	Counties exceeding annual PM2.5 standard (12 ug/m^3)
Los Angeles-South Coast Air Basin	Los Angeles Orange Riverside San Bernardino	Mira Loma, Riverside County
San Joaquin Valley	Fresno Kern Kings Madera Merced San Joaquin Stanislaus Tulare	Clovis, Fresno County
Sacramento Air District	El Dorado Placer Sacramento Solano Yolo	

3.3.3.2. Likely Distribution of Impacts Across Air Basins

According to the emission inventory reviewed in previous sections, the well-stimulation-related emissions of VOC/NO_x and PM are likely to be a small fraction of all the emissions occurring in California. More specifically, oil and gas activities are generally responsible for <5% of the emissions of VOC and PM and for <10% of NO_x to the SJV and SC. Oil and gas activities, however, are responsible for significant fractions of some TAC emissions in the SJV with significant oil and gas activities (30–60%). This is particularly the case for VOC-related TACs.

As natural gas produced from a well with natural gas liquids and oil (wet gas) will be richer in VOCs than that from a well producing mostly natural gas (dry gas) (Jackson et al., 2014), the dry-gas producing regions, such as Sacramento Valley, are expected to have smaller contributions to VOCs and TACs.

As noted above, the contribution of oil and emissions in SC is generally much smaller than that in SJV. The population density in the Los Angeles region is also more than 10 times greater than the SJV region, and is largely collocated with oil and gas activities. As a result, the health hazard from oil and gas emissions can still present a significant problem in SC when source proximity and exposed population are taken into consideration (see Volume II, Chapter 6).

3.4. Hazards

3.4.1. Overview of Well-Stimulation-Related Air Hazards

In this chapter, various chemical species related to well stimulation have been grouped into the following four categories.

1. Greenhouse gases (GHGs);
2. Volatile organic compounds (VOCs) and nitrous oxides (NO_x) emissions leading to photochemical smog generation;
3. Toxic air contaminants (TACs);
4. Particulate matter (PM).

In general, GHGs impact global climate and the other three affect air quality.

GHGs: GHGs include carbon dioxide (CO_2), methane (CH_4), carbon monoxide (CO), nitrous oxide (N_2O), VOCs, and black carbon (BC) (IPCC, 2013, pp. 738-740). These species absorb and emit infrared radiation and thus affect the global radiative balance of the atmosphere. GHG emissions considered here generally produce an increase in the average temperature of the Earth.

VOCs and NO_x: VOC emissions are generated during venting of gases from the well and evaporation of chemicals from flow-back or produced liquids. NO_x emissions associated with WS activities will derive primarily from use of engines powered by diesel or natural gas, which are used directly in WS applications. Processing and compression facilities can also contribute to VOCs/NO_x emissions. VOCs/NO_x lead to environmental and health impacts through various pathways.

- NO_x and VOC can enhance formation of ozone, a key constituent of photochemical smog.

    - Ozone is designated as a criteria pollutant by the Federal Clean Air Act (U.S. EPA, 1994) due to its adverse effects on human health (Bell and Dominici, 2008) and on agriculture productivity (e.g., Morgan et al., 2003). Children, elderly, and people with lung diseases such as asthma are particularly sensitive to ozone concentrations.

    - Ozone and its photolysis also affect climate, because ozone is a greenhouse gas and its photolysis products strongly influence the oxidant content of the atmosphere, which, in turn, affects the lifetimes of other important greenhouse gases and TACs.

- The oxidation products of NO_x and VOC can condense into particle phase and lead to an increase in PM burden. PM formed during these processes is called secondary particulate matter, including particulate nitrate and organic carbon. Secondary particulate matter is associated with increased rates of premature mortality through their deep penetration into the lungs.

- In addition to smog-formation potential, VOCs often also function in the short and long-term as GHGs through their eventual decomposition into carbon dioxide (CO_2).

- Some VOCs are carcinogens or endocrine disruptors and are directly hazardous.

TACs: TACs included in a recent EPA risk assessment are listed in Table 3.4-1. These TACs are emitted in similar processes that contribute to VOCs. TACs can be a concern for workers in the oil and gas industry due to their frequent exposure to TACs. TACs may also present a health concern for those who live near oil and gas operations.

PMs: Diesel equipment used to pump the fluid into the well and the diesel trucks used to bring supplies to the well are the major sources of PM emissions directly related to WS activities. Incomplete combustion at flaring units can also produce PM (soot). PM has both environmental and health impacts. Note that PM considered in previous sections are direct emissions, also known as primary PM. Particles formed through complex reactions in the atmosphere (i.e., secondary PM), such as in NO_x and VOCs oxidation products, are not included in the estimation. Formation of secondary organic carbon is likely to be minor (Gentner et al., 2014), because the hydrocarbons emitted from well stimulation are mostly light alkanes whose oxidation products do not tend to condense into particle phase.

- PM is associated with respiratory health impacts and increased rates of premature mortality through its deep penetration into the lungs. Particulate matter with aerodynamic diameter less than 2.5 micron (PM2.5) and 10 micron (PM10) are both regulated by U.S. EPA as criteria pollutants, due to their adverse health effects.

- Fine particles (PM2.5) are the main cause of regional haze. Reduced visibility is a main concern in national parks and wilderness areas.

Table 3.4-1. TAC emissions ranked by mass emissions rate from oil and natural gas production source category, reproduced from U.S. EPA risk assessment. (U.S. EPA, 2011, Table 4.1-1)

TAC	Emissions (tons per year)	Number of facilities reporting (out of 990 facilities)	Included as TACs indicator species in this report?
Carbonyl sulfide	4,151	727	Y
Hexane	1,666	836	Y
Toluene	1,344	940	Y
Benzene	936	963	Y
Xylenes (mixed)	576	924	Y
Ethyl benzene	111	818	Y
Methanol	88	67	
2,2,4-Trimethylpentane	30	733	
Ethylene glycol	27	727	
Naphthalene	17	754	
Chlorobenzene	11	18	
m-Xylene	11	23	
1,1,1-Trichloroethane	9	4	
Glycol ethers			
- Glycol ethers	5	3	
- Ethylene glycol methyl ether	0.1	5	
- Triethylene glycol	0.02	2	
- Ethylene glycol ethyl ether	0.007	4	
p-Dichlorobenzene	4	13	
Formaldehyde	2	255	Y
Biphenyl	2	2	
Cumene	2	23	
Carbon disulfide	1	726	
Diethanolamine	1	4	
o-Xylene	0.8	7	
1,4-Dioxane	0.6	6	
o-Cresol	0.6	1	
Methylene chloride	0.5	1	
p-Xylene	0.3	7	

Phenol	0.2	16	
Acetaldehyde	0.02	245	Y
Polycyclic organic matter			
- PAH, total	0.02	29	
- Benzo[a]Pyrene	0.002	3	
- Chrysene	0.002	3	
- Anthracene	0.000006	1	
- Benz[a]Anthracene	0.000005	2	
- Benzo[b]Fluoranthene	0.000003	2	
- Benzo[k]Fluoranthene	0.000003	2	
- Dibenzo[a,h]Anthracene	0.000003	2	
- Indeno[1,2,3-c,d]Pyrene	0.000003	2	
Propylene oxide	0.009	4	
Cresols (mixed)	0.009	6	
Ethylene dichloride	0.007	9	
Chloroform	0.004	1	
Hydrochloric acid	0.004	4	
Acrolein	0.002	8	
Dibenzofuran	0.001	1	
Ethylene dibromide	0.0006	5	
Styrene	0.0003	4	
Vinylidene chloride	0.0003	1	
Ethylene oxide	0.00002	1	
Acrylamide	0.00002	1	
Methyl bromide	0.0000005	1	

3.4.2. Hazards due to Direct vs. Indirect Well Stimulation Impacts

Due to their different transport, transformation, and removal mechanisms, species emitted from well stimulation have atmospheric lifetimes ranging from hours (e.g., TACs) to more than 100 years (e.g., CO_2). Accordingly, their spatial impacts range from local, regional, to global scales. GHGs have global impacts over long time scales. As a result, for any given amount of GHG emissions, their impact is not tied to the source locations and emitted time. For the other three categories (NO_x/VOC, TACs, and PM), with generally shorter atmospheric lifetimes and local to regional dispersion, the impacts are closely related to their temporal and spatial allocation at different phases of the well stimulation life-cycle. Some TAC species, such as TAC metals species, can be persistent in the environment and may become more widely dispersed than the reactive organic TACs.

3.4.2.1. Direct Well Stimulation Impacts

On-site air hazards of NO_x/VOC, TACs, and PM affect the surroundings of the well site and downwind areas. Emissions from various phases of on-site activities generally affect the concurring time periods plus a few weeks after, as their atmospheric lifetimes are not longer than a few weeks. The phases of on-site activities and their occurring time frame are as follows:

- Well stimulation application and well completion last days to weeks for a single well and up to a couple of months for multiple wells. During these processes, NO_x and PM are emitted from the on-site diesel engines for trucking and pumping. Hydrocarbons, including smog-forming VOCs and TACs, are the major components from fugitive and vented emissions from well stimulation materials, pipe lines, and flowback water.

- On-site handling of proppant materials could pose a health risk to workers due to particulate matter emissions associated with silica proppant sands.

3.4.2.2. Indirect Well Stimulation Impacts

Some indirect WS hazards are described in this report:

- Well-stimulation-induced production impacts are impacts associated with hydrocarbon production that would not have been economically viable without application of well stimulation technology. The production of additional hydrocarbons on-site may last years after the well completion. Production and processing activities such as dehydration and separation can produce VOC and TAC emissions from equipment leaks, intentional venting from produced water storage tanks, and flaring. PM and NO_x can also be produced by incomplete combustion during flaring and use of diesel engines and compressor engines.

- Supply-chain impacts associated with well stimulation activity include air emissions generated during the course of numerous industrial activities associated with the preparation, distribution, and maintenance of well-stimulation-related materials.

In summary, the well-stimulation-induced hydrocarbon production produces continued air hazards affecting the well site and downwind areas. The supply chain impacts and macroeconomic impacts are more distributed in time and space.

3.4.3. Assessment of Air Hazard

3.4.3.1. Greenhouse Gas Hazard Assessment

GHGs affect global radiative balance. Due to their relatively long atmospheric lifetimes, emissions are well mixed globally once they enter atmospheric circulation. As a result, their impact can be well represented by the mass emitted. As described by the IPCC (2013), the hazard is usually assessed by global-warming potential (GWP), a relative measure of how much heat is trapped by a GHG relative to the amount of heat trapped by the same mass of carbon dioxide. The GHG impacts, listed using current 20-year and 100-year global warming potentials for well-stimulation-relevant gases, are presented in Table 3.2-1. When the GWP of a GHG is applied as a multiplier to its emissions, a CO_2 equivalency amount is derived. Essentially, CO_2 equivalency describes the amount of CO_2 that would have the same GWP as the given amount of emissions of another GHG over a specified time scale (e.g., 100 years). Using the GWP, emissions of a mixture of GHGs can be expressed by a single quantity of CO_2 equivalency to represent the time-integrated (100 years) value of radiative forcing of the mixture.

3.4.3.2. Air Quality Hazard Assessment

3.4.3.2.1. Overview of Air Quality Assessment Methods

NO_x/VOCs, TACs and PM emissions have shorter-term effects than GHGs, and the spatial impacts are not homogeneous due to their shorter atmospheric lifetimes. The air quality of a region is characterized by measurements of ambient concentrations of specific pollutants, including PM and ozone, from central monitors in that region. Before the pollutants emitted from well stimulation are measured by the monitoring devices, they are dispersed by wind and may undergo chemical transformation in the atmosphere. The manner in which the same emissions will affect air quality will differ, depending on the meteorological conditions and the other pollution already present in the atmosphere (the chemical transformations depend on total pollution levels). Although oil and gas activities have relatively low contributions to criteria air pollutant emissions (NO_x, VOCs, PM), as summarized in previous sections, they do in some cases produce relatively high contributions to TACs. Atmospheric dispersion of TACs needs to be tracked with models in order to determine their impacts on populations at varying distances downwind.

There are several methods one might employ to evaluate how well stimulation emissions impact air quality. One could try to determine the impact of emissions through analyzing air quality measurements, comparing air quality on days with high well stimulation activity to days with low well stimulation activity. However, the variability in meteorology and atmospheric chemistry between days would likely overwhelm any signal that might exist from well stimulation variability. Instead of depending only on measurements, air quality models are often used to describe how pollutants are dispersed through the

atmosphere and chemically transformed. The models connect the pollutant emissions to their air quality impacts. Two different air quality models are discussed below; their suitability for application depends on the nature of the pollutant of interest.

Gaussian plume dispersion modeling is a simple yet powerful tool to calculate the evolution of air pollutant concentrations during the course of wind-driven transport and dispersion of non-reactive or first-order decaying pollutants, with decay rate linearly related to concentration. Gaussian plume models (see review by Holmes and Morawska, 2006) are based on analytical solutions to the advection-diffusion equation in simplified atmospheric conditions. Gaussian dispersion models can handle complex terrain and can be adapted to account for some atmospheric processes such as deposition. Gaussian plume models cannot account for interactions between plumes; they are not able to track nonlinear chemistry that leads to secondary pollutant formation in the atmosphere, such as ozone formation. They require relatively little data and computational resources.

A more useful method for calculating ambient pollution levels is to use chemical transport models (CTMs). CTMs solve the advection-diffusion equation numerically for a reactive flow on a gridded domain. CTMs implement chemical mechanisms containing hundreds of reactions. They can also include time-resolved representations of nonlinear chemistry and particle dynamics with various degrees of complexity. CTMs require very detailed meteorological forcing inputs, such as wind velocity, temperature, humidity, etc., at each grid cell of the domain, are computationally expensive, and require advanced training. The advantages of using CTMs to estimate exposure include the capacity to account for the effects of space- and time-resolved influential parameters (e.g., detailed wind and temperature fields) and the capacity to model nonlinear processes such as second-order chemistry and particle dynamics in a time-resolved manner. This approach is suited for simulating concentrations of secondary pollutants such as ozone and secondary organic carbon.

Air quality hazards discussed here include species of emissions associated with well stimulation (directly emitted species) and the pollutants formed through chemical transformation of these emissions in the atmosphere (chemically formed species). Suitability of air quality models for assessing these two types of pollutants is discussed further in the following sections.

3.4.3.2.2. Well-Stimulation-Induced Air-Quality Hazard Assessment: Directly Emitted Species

Directly emitted species can be tracked with Gaussian plume dispersion models, which link the amount of emissions from the source locations to changes in concentrations. These species include all the air hazards considered in previous emission inventories (e.g., NO_x/VOCs, TACs, and primary PM). These can be done for on-site emissions of selected case studies, where a clear emission boundary can be defined. Modeling and analysis protocol is briefly described below.

- Required inputs:
    - Meteorological data (obtained from national weather service): hourly or daily wind speed and direction, amount of atmospheric turbulence, ambient air temperature, inversion height, cloud cover and solar radiation
    - Emission parameters: source location and height, spatial characteristic of source as in point (i.e., smoke stack), line (i.e., highway), or area (i.e., oil field), and exit velocity and mass flow rate of the plume
    - Terrain elevations and surface characteristics: ground elevations at the source and at the locations where pollutant level are to be computed, surface roughness
- Model simulation: use the meteorological data and surface characteristics to drive the dispersion model for emitted pollutant of interest, accounting for depositional loss and first-order decay.
- Post-model analysis: enhancement in ambient concentrations of the pollutant of interest can be plotted as a function of time and space and summarized by season. The most impacted times and locations can be identified and used for subsequent exposure and health studies.

3.4.3.2.3. Well-Stimulation-Induced Air-Quality Hazard Assessment: Chemically Formed Species

Chemically formed species such as ozone and secondary PM are not directly emitted and thus cannot be tracked by dispersion models, as there is no discrete "source location." Another challenge is that the formation chemistry of these pollutants is often nonlinear. In other words, the amount of pollutant formed cannot be linearly scaled from its precursor emission quantities, but rather depends on the pollution levels present in the air. For example, in a NO_x-rich environment such as a densely populated Los Angeles urban area, additional NO_x emissions from well-stimulation-related activities may actually decrease ambient ozone concentration locally, while affecting downwind regions (Rasmussen et al., 2013). In NO_x-poor areas, such as a remote well pad location in the San Joaquin Valley, the opposite is true, i.e., well-stimulation-related NO_x emissions contribute to an increase in ambient ozone levels (Rasmussen et al., 2013). Chemical transport models (CTMs) are required in this case to simulate the formation process of these species from their precursors. In the case of ozone, CTMs track the production and removal of ozone as its NO_x/VOC precursors disperse from the source location downwind accounting for the nonlinear chemistry. Conducting computer simulation with CTMs is beyond the scope of this study. Many past studies have investigated ozone and secondary PM responses to changes in emissions (Jin et al., 2008; 2013; Rasmussen et al., 2013; Chen et al., 2014) in California.

3.5. Alternative Practices to Mitigate Air Emissions

This section presents a review of alternative practices that reduce emissions of pollutant and GHG related to well stimulation with a focus on direct hazards.

3.5.1. Regulatory Efforts to Prescribe Best Practices

Many states outside of California where hydraulic fracturing takes place have begun to regulate the overall environmental impacts of the oil and gas industry, by requiring emission controls and best practices. As reviewed in Moore et al. (2014), Colorado, Wyoming, Montana, and New York have taken the most aggressive regulatory steps to reduce both pollutant and GHG emissions (Table 3.5-1). In the regulations passed from 2007 to 2009 in Colorado, operators are required to apply alternative practices and controls to reduce VOC emissions, including use of "green completion" or reduced emission completion technologies at oil and gas wells when technically feasible, and control evaporative emissions from condensate and oil storage tanks. In the northeastern Front Range O3 nonattainment area, further actions are required, such as use of no-bleed or low-bleed pneumatic devices.

In California, regulations are set at local air district levels. San Joaquin Valley Air Pollution Control District Rule 4402 regulates the emissions of VOCs from crude oil wastewater sumps. Under this rule, VOC emission control, such as a covering in place, is required for any produced water containing over 35 mg/L of VOCs. Small oil producers and "clean produced water" containing less than 35 mg/L are exempt from the rule. The South Coast Air Quality Management District (SCAQMD), have more stringent regulations for open pits. The SCAQMD (Rule 1176) for example, requires produced water in open pits contain less than 5 mg/L VOC's, compared to the San Joaquin threshold of 35 mg/L.

At the national level, in 2012, the U.S. EPA released a set of new source performance standards (U.S. EPA, 2012) which were phased in starting in late 2012, with full effect in early 2015. The standard requires the use of green completion technologies and reduced VOC emissions from temporary storage tanks during well completion. Historically, the fluids and gases in flowback water are routed to an open-air pit or tank to allow evaporation. Green completion captures liquids and gases during well completion with temporary processing equipment for productive use.

Further VOC and TACs controls are required by the rule (U.S. EPA, 2012), including limiting emissions of VOCs from a new single oil or condensate tank to four tons per year, and limiting the hazardous air pollutants benzene, toluene, ethylbenzene, and xylenes (BTEX) from a single dehydrator to one ton per year. In addition to VOC reduction through vapor controls at temporary storage tanks, green completion also benefits the control of methane emissions by essentially requiring natural gas companies to capture the liquid and gas at the wellhead immediately after well completion instead of releasing it into the atmosphere or flaring it off.

The U.S. EPA also adopted multiple tiers of emissions standards for new diesel engines that may influence emissions incurred by the trucking and pumping processes related to well stimulation. Vehicle and engine pollutant emissions, including NO_x, non-methane hydrocarbons, CO, and PM can be largely controlled if new engines, vehicles, or equipment is used that meet the latest emission tier. However, the long useful life of diesel equipment and vehicles has prompted California to add additional emission requirements for in-use on-road diesel trucks and other diesel equipment. For example, California requires that almost all heavy-duty trucks and buses that currently operate in the state meet stringent particulate matter emission standards now, and meet stringent NO_x emission standards within the next decade.

3.5.2. Control Technologies and Reductions

Many emissions from the above three key processes can be addressed with best controls and alternative practices. U.S. EPA (2012) estimates implementation of green completion will result in a 95% reduction of VOC emissions and a 99.9% reduction in SO2 emissions. These green completions technologies are evolving over time due to relative novelty, and will likely improve with additional deployment (e.g., cost could be reduced). Allen et al. (2013) reported low leakage rates from well completions after some of the controls listed above were implemented compared to uncontrolled processes, and ICF International (2014) analyzed the costs and viability of methane reduction opportunities in the U.S. oil and natural gas industries. Harvey et al. (2012) reviewed 10 technologies with the capability estimated to reduce more than 80 percent of methane emissions in the oil and gas sector. In addition to methane emissions, many of the technologies have the co-benefit of reducing explosive vapors, hazardous air pollutants, and VOCs.

Large reductions in pollutants and GHGs through use of new technologies and compliance with regulations should be interpreted as best-case scenarios and should not be used to estimate real-operation efficacy. For example, current requirement in VOC reductions from tanks in Colorado are 90% in the summertime and 70% in other times of year of the actual annual average reduction in emissions. However, actual reductions were estimated to be 53% (State Review of Oil & Natural Gas Environmental Regulations, 2011). More importantly, in fast-developing areas, increasing numbers of new wells may counter the overall pollution-control benefits resulting from emission controls applied to individual wells. Despite tightening of emission standards for the oil and gas industry in Colorado, the oil and gas-related VOC measurements made in the non-attainment area in Erie showed a continued increase (Thompson et al., 2014). System-wide emission reduction needs careful planning and monitoring, accounting for both technology advances and industry development and expansion.

Table 3.5-1 summarizes the control technologies and alternative practices available in the literature according to their related processes, as reviewed in previous sections. The national- and state-level adoptions of the various practices are also noted. Depending on their attainment status, local air districts may have more stringent regulations of air

emissions than the state level, such as permitting programs for new sources. For example, while emission data from the oil and gas industry are collected in Texas, regulation of emissions is limited to the Houston and Dallas−Fort Worth federal ozone standard non-attainment areas. These local regulations can be important, but are not included in the table.

Table 3.5-1. Best control or practices for controlling emissions from key processes.

Process	Best Control or Practice	Description	Emissions addressed	Regulation adoption
Trucking and pumping supplies/fluid to the well	U.S. EPA tier 4 diesel engines	Installed with control technologies to reduce emissions from diesel equipment by 90% compared to the one from 1990s.	NO_x, PM	
	Use of newest truck built since 2010	Included exhaust controls	NO_x, PM	
Venting and flaring	Green completion	Capture liquids and gases coming out of the well during completion.	CH_4, VOCs, and TACs	U.S. EPA, Colorado, Wyoming, Montana.
	Plunger lift system	Collect liquids inside the wellbore and capture methane.	CH_4, VOCs, and TACs	
	Dehydrator emission controls	Capture methane with emission control equipment placed on dehydrators	CH_4, VOCs, and TACs	Montana
	Methane capture during pipeline maintenance and repair	Re-route or burn methane, use of hot tap connections, de-pressuring the pipeline etc.	CH_4, VOCs, and TACs	
	Low-bleed or no-bleed pneumatic controllers	Reduce methane release to the atmosphere, or move away from gas-operated devices.	CH_4, VOCs, and TACs	Colorado
Fugitive and/ or evaporation of gas and chemicals	Dry seal systems and improved compressor maintenance	Reduce emissions from centrifugal compressors and reciprocating compressors	CH_4, VOCs, and TACs	Montana
	Tank vapor recovery units	Capture gases released from flashing losses, working losses, and standing losses	CH_4, VOCs, TACs.	Colorado, Montana.
	Leak monitoring and repair	Monitoring potential leaks at equipment locations subject to high pressure.	CH_4, VOCs, TACs.	

3.6. Data Gaps

A number of data gaps exist in understanding emissions from well stimulation activities. The challenges that exist include:

- Few studies exist that directly measure emissions from oil and gas activities;

- Even fewer studies exist that directly examine well stimulation activities, none of which occurred in California; and

- It is unclear how applicable results from a given study conducted elsewhere might be to California well stimulation activities, due to significant differences in treatment and regulation of both air emissions and well stimulation between states.

These challenges noted, the available studies that were deemed most relevant to understanding air impacts of well stimulation are reviewed below. These studies can be broken down into studies that will directly measure or assess emissions at a facility or device level (henceforth "bottom-up" studies) and studies that perform indirect or remote measurement of gas concentrations and then estimate emissions from these measurements (henceforth "top-down").

3.6.1. Bottom-Up Studies and Detailed Inventories

A number of experimental studies or bottom-up inventories were performed in regions with significant well stimulation activities. These studies include:

- Study of direct emissions from well stimulation by Allen et al. (2013).

- Study of direct emissions from hydraulically fractured natural gas wells by ERG (Eastern Research Group) and Sage Environmental.

- Study of emissions in the Eagle Ford hydraulically fractured oil basin.

- The Barnett area special inventory.

3.6.1.1. Allen et al. (2013) Study of Hydraulic Fracturing Processes

3.6.1.1.2. Overview of Study and Goals

Aside from the Fort Worth study, the most significant scientific assessment examining the GHG impacts of well stimulation was conducted by Allen et al., funded by the Environmental Defense Fund and with the cooperation of operators (Allen et al., 2013).

3.6.1.1.2. Methodology

This study calculated methane emissions and emissions factors at 190 natural gas facilities across four regions of the country where well stimulation was utilized (Appalachian, Gulf Coast, Mid Continent, and Rocky Mountain). Of these natural gas facilities, they examined 150 production facilities with 489 wells, along with 27 well completion flowbacks, nine well unloadings, and four well workovers across nine different operators.

In order to capture emissions from flowback, completion, unloading, and workover operations, they bagged and diverted all hatches to temporary stacks, where the emissions were analyzed and fluxes calculated. For the production facilities, they utilized an IR camera and recorded leaks for equipment that were detected by the camera. If leaks were detected, they utilized a Hi Flow sampler to measure emissions rates. All of these leaks were reported under the category "Equipment Leaks." (Included in this category are valves, connectors, and well equipment.) In addition, Allen et al. reported detailed results for pneumatic devices, all of which were analyzed with a high-flow sampler.

3.6.1.1.3. Key Findings

The most significant finding was that, overall, methane emissions were found to be slightly lower than the 2011 U.S. EPA inventories. This was the result of measured methane emissions from completion flowbacks that were an order of magnitude lower than the U.S. EPA inventory, offset by higher emissions rates for chemical pumps, pneumatic controllers, and equipment. The overall emissions estimates report a methane leakage rate of 0.42% compared to the U.S. EPA value of 0.47%.

3.6.1.2. City of Fort Worth Air Quality Study

3.6.1.2.1. Overview of Study and Goals

A comprehensive study of direct measurements of emissions from natural gas production in a region of hydraulic fracturing is the "City of Fort Worth Natural Gas Air Quality Study." This was commissioned in 2010 by the city of Forth Worth, TX, and prepared by Eastern Research Group along with Sage Environmental Consulting, LP (ERG/SAGE 2011). The goals of the study were to quantify the environmental and public health and safety impacts of hydrocarbon production activities. They measured leaks from 388 sites, which included 375 well pads with 1,138 wells. The results of this study were published in a report as well as spreadsheets that detail component-level emissions for each site.

3.6.1.2.2. Study Methods

At each of the well locations, leaks were recorded with the following methodology. Initially a FLIR infrared camera was utilized to detect large leaks. The emissions flux for these large emitters was measured with a Hi Flow Sampler. In addition to recording these large leaks, 10% of all valves and connectors were recorded with a toxic vapor analyzer, and any leak greater than 500 ppmv was recorded and measured with a Hi Flow Sampler. Additionally, Summa Canisters were utilized to provide gas speciation.

Leaks were placed into three broad categories: "valves," "connectors," or "other." Leaks were also classified by study authors using detailed categorization with 94 designations. Neither of these categorization schemes align well with U.S. EPA or other established methodologies, making construction of emissions factors difficult from this dataset.

3.6.1.2.3. Study Findings

As is typical for analysis of gas leakage, emissions are driven by a small percentage of leaks. In this case, 6% of wells account for half of the total measured emissions in the study on a well basis, and the average emissions rate ($\sim 1 \times 10^4$ kg/year) aligns with the 75th percentile.

While this study represents a large group of measurements on a significant number of wells that were hydraulically fractured, it is not clear how applicable the observed emissions rates are to California. Also, since the Barnett shale studied in the report is a dry gas region, data would be most applicable to analogous types of environments, such as gas production in the northern SJV region.

3.6.1.3. Alamo Area Council of Governments Eagle Ford Emissions Inventory

3.6.1.3.1. Overview of Study

The Alamo Area Council of Governments (AACOG) conducted an oil and gas emissions inventory for criteria air pollutants. Though some work is still in progress, the bulk of the results were released as a technical report in 2013 (AACOG, 2014). The purpose of the report was to quantify criteria air pollutants (CO, NO_x, and VOCs in particular) from oil and gas drilling, completion, production, and processing (midstream) operations in the Eagle Ford shale formation. Due to regulatory constraints, they did not conduct any measurements of GHG emissions.

3.6.1.3.2. Methods

As part of the study, the authors developed detailed activity counts of drilling rigs, compressors, compressor stations, equipment at production facilities, as well as timelines for production activities (such as drilling and completions). Emissions were calculated from these activity counts with existing emissions factors from the literature or from the Texas Commission on Environmental Quality. Specific emissions factors were calculated for compressor stations as well as drilling rigs, while activity counts and emissions factors for production facilities were aggregated at the county level. They then utilized these aggregated data as inputs to an air-quality impact model, and also provided an uncertainty analysis discussing potential future scenarios of well stimulation air quality impacts in the Eagle Ford.

3.6.1.4. Barnett Shale Special Inventory

3.6.1.4.1. Overview of Study

In response to observing VOC leakage from surface equipment coinciding with the growth of gas production in the Barnett shale, the Texas Commission on Environmental Quality (TCEQ) conducted an emissions inventory of upstream and midstream sources in the

twenty-three counties that overlie the Barnett shale. The study was conducted over two phases between 2009 and 2011 and presented county-aggregated emissions factors and activity counts covering the 2009 production year. The pollutants reported in the publicly available summary are NO_x, VOCs, and HAPs (though more detailed information can be requested and are included in the internal TCEQ database).

3.6.1.4.2. Methods

TCEQ collected these data through operator self-reporting. The first phase of the project, which covered activity counts, acquired data from 9,123 upstream and 519 midstream facilities. Results were generated for twenty-two different equipment categories. Produced water storage tanks and piping components are the largest sources of activity, with over 15,000 tanks and 12,500 piping component fugitive areas in the sample data (TCEQ, 2010). Part one of the special inventory included activity counts of higher emissions equipment (TCEQ, 2010).

The second phase of the project was conducted over 2010–2011 and accounted for emissions estimates for sites and equipment at 8,500 sites (TEQ, 2011). The emissions rates for NO_x, VOCs, and HAPs were computed either through taking site-specific samples or through the utilization of TCEQ emissions factors which were provided in the surveys. This allowed for emissions rates as categorized by equipment type across the Barnett region (tons per year). More detailed speciation and some site-level emissions rates can be obtained through contacting TCEQ, but this was determined to be beyond the scope of this work. Maps of results from the TCEQ Barnett inventory are available (TCEQ, 2014).

3.6.2. Top-Down Studies and Experimental Verification of California Air Emissions Inventories

Understanding the accuracy of emissions inventories is an important factor in understanding the impact of well stimulation on air quality in California. If experimental evidence suggests that inventories of the air pollutants of concern (GHGs, VOC/NO_x, TACs, PM) are inaccurate, then this could point to the need for improved understanding of poorly understood or novel contributors to air emissions, such as well stimulation.

Using observations to determine the accuracy of inventories is difficult, and such experimental studies tend to be expensive and performed in a sparse set of locations and time periods. Thankfully, California air quality is the topic of a significant number of experimental studies, over many decades. For this reason, observations that allow assessment accuracy of inventories are numerous in California compared to other regions. A prime example of such activities is the recent large CalNex effort, funded by CARB and NOAA (National Oceanic and Atmospheric Administration), to examine a number of scientific questions at the interface of climate and air quality. CalNex resulted in the publication or submission of approximately 100 peer reviewed scientific papers over a four-year period, with flights and samples occurring in 2010 (Ryerson et al., 2013). A

key scientific goal of CalNex was the assessment of CARB inventory accuracy. For more information, the CalNex campaign is introduced in Ryerson et al. (2013) and summary results to scientific questions are presented in a synthesis report (Parrish, 2014).

Using observations to check the accuracy of CO_2 inventories is difficult (Ryerson et al., 2013). This is because CO_2 sources are ubiquitous, and natural diurnal variation in sources and sinks of CO_2 makes discerning a signal challenging. Noting these challenges, CO_2 observations from CalNex agree within experimental error with scaled inventory results (Parrish, 2014, Finding F1). Similar accuracy was found for the CARB CO inventory (Parrish, 2014, Finding F5). NO_x emissions were also found to be in general agreement with CARB inventories, with some caveats about spatial distributions of emissions (Parrish, 2014, Finding F6). No studies of PM or TACs with specific implications for oil and gas or well-stimulation-related emissions were found.

Notably, in CalNex, significant divergence or error was found in comparing CH_4 and VOC observations to inventories. Importantly, in each of these cases, oil and gas sources were examined as specific possible contributors to excess emissions.

Numerous studies, including some before CalNex, examine CH_4 concentrations in California. Some of these studies make explicit comparison to CH_4 inventories, with some specifically examining the role of oil and gas sources in California CH_4 emissions.

CH_4 relevant studies reviewed below are:

- Wunch et al. (2009): Emissions of greenhouse gases from a North American megacity
- Zhao et al. (2009): Atmospheric inverse estimate of methane emissions from Central California
- Hsu et al. (2010): Methane emissions inventory verification in Southern California
- Wennberg et al. (2012): On the sources of methane to the Los Angeles atmosphere
- Peischl et al. (2013): Quantifying sources of methane using light alkanes in the Los Angeles basin, California
- Jeong et al. (2013): A multitower measurement network estimate of California's methane emissions
- Jeong et al. (2014): Spatially explicit methane emissions from petroleum production and the natural gas system in California
- Johnson et al. (2014): Analyzing source apportioned methane in northern California during Discover-AQ-CA using airborne measurements and model simulations

VOC-relevant studies include:

- Gentner et al. (2014): Emissions of organic carbon and methane from petroleum and dairy operations in California's San Joaquin Valley

These studies are reviewed below including their methods and their key results as related to oil and gas CH_4 sources in California. Findings are summarized to determine if there is a consensus regarding the accuracy of California inventories, and whether well-stimulation-associated emissions could be responsible for inventory discrepancy.

Note that top-down atmospheric studies typically report emissions in Tg of CH_4. At typical upstream (production) compositions, 1 Tg of CH_4 (or 52.2 BCF of CH_4) is equal to about 60 BCF (billon cubic feet) of produced natural gas.

3.6.2.1. Wunch et al. (2009)

Wunch et al. (2009) analyzed air column concentrations of CH_4 and CO_2 in the atmosphere of the south coast air basin (SoCAB) in 2007–2008 (Wunch et al., 2009). Fourier transform spectroscopy of sunlight was performed for 131 days of observations. This study cannot reliably partition CH_4 emissions into oil and gas and non-oil and gas sources, due to lack of isotopic sampling and lack of observations of higher alkanes which may provide a chemical "fingerprint" of an oil-and-gas-associated source of CH_4.

Wunch et al. estimate CH_4 emissions in the SoCAB region of 0.6 (+/-0.1) or 0.4 (+/-0.1) Tg CH_4 per year, depending on whether the CARB CO_2 inventory or CARB CO inventory is used to provide temporal scaling of emissions to relate atmospheric concentrations to emissions rates. They compare this result to the CARB CH_4 inventory as follows: CH_4 from all "urban sources" (non-forestry, non-agriculture sources of CH_4) is scaled to the region using the fraction of California population in the SoCAB region. Thus, they argue that the CARB CH_4 inventory underpredicts CH_4 emissions.

3.6.2.2. Zhao et al. (2009)

Zhao et al. (2009) utilized data from a tall tower in the northern SJV, with measurements taken at ~90 m and ~480 m heights. Observations were performed from October to December 2007. A high precision (0.3 ppbv) cavity ring-down spectrometer was used to measure CH_4 concentrations at five-minute intervals. These observations were coupled to an atmospheric transport model. The model was used in an inverse approach to estimate, for a given gas concentration observation, where the gases observed are likely to have been emitted (parcels of air are modeled backward in time for five days). The coupling of tower observations of gas concentrations with simulation allowed an estimate of the likely emissions rates in a spatially resolved manner. They compared their emissions estimates to the Emissions Database for Global Atmospheric Research (EDGAR) spatially resolved emissions inventory (EDGAR v. 3.2).

Zhao et al. find that for the region (central California) and time period (October–December 2007) of analysis, actual emissions are estimated to be 37% +/- 21% higher than annually averaged inventory estimates from the EDGAR inventory. In particular, they believe that livestock emissions are underestimated by an even larger fraction. They do not compare their results to the CARB inventory, as at the time of their study, there existed no spatially resolved version of the CARB inventory (see below for more discussion).

3.6.2.3. Hsu et al. (2010)

Hsu et al. (2010) performed analysis of captured flasks of air from a remote location (Mt. Wilson observatory) to estimate the concentrations of gases in a well-mixed sampling of air from the Los Angeles region. Their study is the Los Angeles County portion of the SoCAB region. In order to estimate CH_4 flux from CH_4 concentrations, they used observed ratios of CH_4 to CO in the atmospheric observations, and coupled this ratio to the CARB CO inventory to estimate CH_4 emissions rate.

Hsu et al. estimated methane emissions of 4.2 +/- 0.12 Mt CO_2 eq. GHGs per year. They then compared this to the CARB inventory of the time, which estimated CH_4 emissions of ~3 Mt CO_2 eq./y from the study region. Thus, they argued that the CARB CH_4 inventory underpredicts CH_4 emissions from the study region.

3.6.2.4. Wennberg et al. (2012)

Wennberg et al. (2012) combined observations of a variety of types to estimate emissions of methane in the SoCAB region. They included air flasks from remote observation locations, aircraft observations from a set of flight campaigns, as well as ground-based Fourier transform spectroscopy to estimate air-column concentrations of CO_2, CO, and CH_4. This study can be seen as an extension and improvement of the work of Wunch et al. (2009) and Hsu et al. (2010). In a novel advance from those previous studies, Wennberg et al. used C_2H_6 concentrations to attempt to partition emissions into various sources.

Wennberg et al. estimated CH_4 emissions in the study region to be 0.44 +/- 0.15 Tg CH_4/y. They compared this to an inventory based largely on CARB sources, which has a scaled emissions estimate for the study region of 0.21 Tg CH_4/y. Thus, they argued that CH_4 emissions may be approximately two times larger than an inventory approach would produce in the region.

3.6.2.5. Peischl et al. (2013)

Peischl et al. (2013) use a variety of sampling methods with aircraft data to estimate CH_4 emissions in the SoCAB region. Similar to other studies noted above, they used CO concentrations and the CO inventory to estimate CH_4 fluxes from CH_4 concentrations.

Peischl et al. created estimates for all sources of CH_4 (0.41 +/- 0.04 Tg CH_4/y) and oil and gas sources (0.22 +/- 0.06 Tg CH_4/y). Their estimate of oil and gas sources was based on concentrations of seven alkanes observed in the air, apportioned to sources using assumed compositions of emissions from those sources in a least-squares-fitting approach. They compared this oil and gas result to a CARB-inventory-estimated quantity of 0.064 Tg CH_4/y. Thus, they estimated that in the SoCAB region, inventory methods underestimate CH_4 emissions by a factor of 3.5 (2.5 to 4.4).

3.6.2.6. Jeong et al. (2013)

Jeong et al. (2013) used observations from five locations in California's central valley (SJV), including one tall tower (samples at ~90 and 480 m) and four small towers (samples at ~10 m). They combined these observations with aircraft observations of the Pacific boundary (i.e., incoming CH_4 concentrations) and urban regions. They compared these observations to a spatially resolved version of the CARB inventory, in which the CARB 2008 inventory was scaled to a detailed spatial emissions model. They also used the EDGAR spatially resolved inventory as a source of comparison emissions estimates, but this report focuses on California Greenhouse Gas Emissions Measurement program (CALGEM) comparisons, as these are more consistent with CARB inventory methods. In this study, atmospheric transport was modeled using an inverse approach with the WRF-STILT model (coupled weather research and forecasting–stochastic time-inverted lagrangian transport model). This approach traced "particles" of air backward through time in a time-inverted weather simulator, to estimate from where gases observed in particular locations were likely to have been emitted. This approach has been used in a number of national and regional atmospheric studies of GHGs.

The "prior" model in the Bayesian analysis of Jeong et al. (2013) is the spatially resolved CALGEM inventory, which predicts CO_2eq. CH_4 emissions of 28 TgCO_2eq./y. The emissions estimated incorporating the observations (the posterior estimate) is 48.3 Tg CO_2eq./y (+/- 6.5 at 1σ level). Thus, they argued that the CALGEM inventory is likely underpredicting California methane emissions.

3.6.2.7. Jeong et al. (2014)

Jeong et al. (2014) generated a much more detailed spatially resolved estimate of emissions from the California oil and gas industry than used in other studies. For example, well-level activity data (production of oil, gas, and water) were compiled from DOGGR data sources, while gas processing data were derived from federal U.S. EPA reporting. Also, pipeline fugitive emissions were modeled using detailed spatial representations of the California oil and gas distribution system. These activity factors were coupled to emissions factors (i.e., emissions per unit of activity) generally derived from U.S. EPA emissions factors. Lastly, they augmented this detailed "bottom-up" approach with data from the SoCAB region collected in atmospheric studies noted above (Wunch et al., 2009; Hsu et al., 2010; Wennberg et al., 2012; Peischl et al., 2013).

Jeong et al. (2014) found that using non-CARB emissions factors with detailed California activity data results in emissions estimates that are significantly larger than either the CARB GHG inventory or the CARB oil and gas survey. For example, the initial bottom-up result from their study was 330 Gg CH_4/y of emissions from all portions of the California oil and gas sector (uncertainty range 220-518 Gg CH_4/y). This compared to CARB GHG inventory and survey results of 210 and 204 Gg CH_4/y respectively. When they scaled their bottom-up approach to better match atmospheric observations, they found that their bottom-up estimate increases to 541 +/- 144 Gg CH_4/y. Thus, Jeong et al. (2014) found that the CARB inventory significantly under-predicts CH_4 emissions compared to what would be expected using existing U.S. EPA emissions factors or using atmospheric data.

3.6.2.8. Johnson et al. (2014)

Johnson et al. (2014) utilized aircraft observations in a series of flights taken in January and February of 2013 in the San Francisco Bay Area and northern San Joaquin Valley. They then coupled these observations to a 3-d atmospheric chemical transport model (GEOS-Chem) to derive flux estimates for CH_4 in the study region. They compared their results to the EDGAR spatially explicit emissions inventory.

They found that the EDGAR emissions inventory must be scaled by a factor of 1.3 to arrive at results that agree with atmospheric observations. They found that increasing oil and gas and waste (landfill) emissions by a factor of two results in a decrease in overall model bias, but degrades the model fit by overpredicting background CH_4 values. They found that increasing livestock emissions between a factor of two to seven would result in reduced overall model-observation bias and decrease overall RMSE (root mean square error). They argued that a correction factor of two for livestock emissions is not sufficient to correct overall underprediction, while a factor of seven is an upper limit. Therefore, Johnson et al. argued that in the SFBA and northern SJV region, it was likely that livestock CH_4 emissions were underestimated in existing spatial inventories. They did not directly compare their results to CARB inventories.

3.6.2.9. Gentner et al. (2014)

Gentner et al. (2014) used ground-based measurements with a meteorological transport model to examine the role of petroleum operations on emissions of hydrocarbon-derived VOCs. The meteorological model was used similarly to other studies above: back trajectories of parcels of air were traced over 6- and 12-hour periods to estimate sources of measured VOCs at the sampling location. These sources were then compared to spatial distributions of petroleum production operations (as well as dairy operations).

Gentner et al. found reasonable agreement between their sampling efforts in Bakersfield and the CARB inventory results. They found that 22% of VOC measured at their site could be attributed to petroleum operations, which was similar to their reported CARB partitioning for the SJV air district of 15%. Dairy sources were found to contribute 22%

(compared to 30% for CARB inventory) and motor vehicles 56% (compared to 55% for CARB inventory). In contrast, a smaller inventory comparison to just the Kern County portion of the SJV air district implies less petroleum emissions observed than expected in the inventory (as should be expected, given large petroleum operations in Kern County).

Gentner's explained fraction of ROG emissions in the SJV region, partitioned 15% to petroleum operations, is not in alignment with our computed value of 8% above. The causes for these differences were unable to be determined.

3.6.2.10. Summary Across Studies: How do Experimental Observations Align With California Inventory Efforts?

Taking the above experimental efforts in the aggregate, some general conclusions can be drawn about the California GHG inventory:

- Experimental evidence points to CARB inventories generally underpredicting CH_4 emissions in California. The degree of estimated underprediction varies by study, and no scientific consensus has yet emerged.

- Uncertainties are not reported for CARB inventories, and uncertainties for experimental studies are typically on the order of 15–30%.

- Studies point to livestock and oil and gas sources as drivers of these excess CH_4 emissions. There may be a regional effect observed here: livestock underprediction may be more important in studies focused on the northern SJV, while oil and gas under-prediction may be more important in studies focused on southern SJV and SC air districts.

- There is still considerable uncertainty in the observational literature about the precise level of CH_4 emissions from the California oil and gas industry.

- None of the experimental studies performed in California targeted well stimulation activities, so none of these studies provides evidence as to the accuracy of potential inventory treatment of well stimulation activities.

3.7. Findings

- Fields that are currently produced with well stimulation technologies in California have, on average, lower greenhouse gas emissions from oil production than a typical California oil field, and lower than fields produced without well stimulation.

- Because California produces a significant amount of high carbon intensity heavy crude oil in non-stimulated fields, reducing the use of well stimulation could result in an increasing reliance on more GHG-intensive sources of crude oil. More analysis involving market-based life cycle analysis is required to understand the potential impacts of removing hydraulic-fracturing-induced oil from California's oil supply.

- Current California air quality inventory methods likely include at least some well-stimulation-related emissions in their results. Inventory methods are not designed to estimate well stimulation emissions directly, and it is not possible to determine well stimulation emissions from current inventory methods.

- Using current inventory methods, the oil and gas sector is a minor contributor to GHG, emissions in California, contributing about 4% to state emissions.

- In the San Joaquin Valley, the oil and gas sector is a material contributor to TAC emissions, especially hydrogen sulfide, which is emitted mostly from oil and gas sources. In the San Joaquin Valley, the oil and gas sector contributes 30% of SO_x and 8% of ROG emissions.

- In the South Coast region, the oil and gas sector emits less than 1% of all studied species.

- Due to the fact that about 20% of California production is induced by well stimulation, direct and indirect impacts from well stimulation should be approximately 1/5 of above impacts.

- Local effects of air emissions can be more significant than the above analyses at the air basin scale. See Volume II, Chapter 6 for more discussion of local air impacts and impacts on populations that live near production sites.

- More research is required on overall leakage rates from oil and gas systems to better understand the breakdown of VOC and TAC emissions between sources (e.g., produced hydrocarbons, solvents, other process chemicals).

- Regulatory processes are currently in flux in a number of U.S. states, as well as federally. Current regulatory processes (e.g., federal EPA regulations) will greatly reduce some previously large emissions sources from well stimulation.

- Technologies exist to greatly reduce GHG and VOC emissions from well stimulation. Well stimulation direct emissions can be controlled through reduced emissions completions technologies.

- There are currently a number of significant gaps in the scientific literature with respect to the air emissions from well stimulation in particular, as well as in understanding air emissions from the oil and gas sector more generally.

3.8. Conclusions

Well stimulation is a potential source of air quality impacts in California. The oil and gas industry in general is a minor source of California's GHG emissions. In regions with large oil and gas sectors, such as the SJV region, the oil and gas industry is a major contributor to some TAC emissions and to SO_x emissions. The oil and gas industry materially contributes to ROG emissions as well. Because current inventory methodologies used in California were not designed to differentiate well stimulation emissions from other oil and gas emissions, it is not currently possible to estimate direct air emissions from well stimulation in California.

A number of regulatory and technical approaches to reducing emissions from well stimulation (and oil and gas production more generally) are available and currently used in at least some jurisdictions. The regulation of well stimulation emissions is still in flux at state and federal levels, and California is no exception.

The few studies that have examined well stimulation emissions directly have found that emissions are generally small, especially if control technologies are applied (as required by federal regulations for stimulated natural gas wells). These studies are few in number, so uncertainty still remains about the sources of air emissions from well stimulation. Given the importance of the California oil and gas sector for some emissions sources (e.g., TACs in the San Joaquin Valley), a significant induced increase of oil and gas production due to well stimulation could result in meaningful additional indirect air impacts. For other air quality concerns, or for smaller induced production volumes, it is unlikely that well stimulation will materially affect air quality.

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Chapter Four

Seismic Impacts Resulting from Well Stimulation

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4.1. Abstract

Induced seismicity refers to seismic events caused by human activities. These activities include injection of fluids into the subsurface, when elevated fluid pore pressures can lower the frictional strengths of faults and fractures leading to seismic rupture. The vast majority of induced earthquakes that have been attributed to fluid injection were too small to be perceptible by humans. However, events induced by injection have on several occasions been felt at the ground surface, and in extremely rare cases have produced ground shaking large enough to cause damage. These larger events can occur when large volumes of water are injected over long time periods (months to years) into zones in or near potentially active earthquake sources.

The relatively small fluid volumes and short time durations (hours) involved in most hydraulic fracturing operations are generally not sufficient to create pore-pressure perturbations of large enough spatial extent to generate induced seismicity of concern. Current hydraulic fracturing activity is not considered to pose a significant seismic hazard in California. To date, only one felt earthquake attributed to hydraulic fracturing in a California oil or gas field has been documented, and that was anomalous because it was a slow-slip event that radiated much lower energy at much lower dominant frequencies than ordinary earthquakes of similar size.

In contrast to hydraulic fracturing, earthquakes as large as magnitude 5.7 have been linked to injection of large volumes of wastewater into deep disposal wells in the eastern and central United States. Compared to states that have recently experienced large increases in induced seismicity, water volumes disposed per well in California are relatively small.

Despite decades of production and injection in oil and gas fields, extensive seismic monitoring, and vigorous seismological research in California, there are no published reports of induced seismicity associated with wastewater disposal related to oil and gas operations in the state. However, the potential seismic hazard posed by current water

disposal in California is uncertain because possible relationships between seismicity and wastewater injection have yet to be studied in detail. Injection of larger volumes of produced water from increased well stimulation activity and the subsequent increase in oil and gas production could conceivably increase the hazard. Given the active tectonic setting of California, it would be prudent to carry out assessments of induced seismic hazard and risk for future injection projects, based on a comprehensive study of spatial and temporal relationships between wastewater injection and seismicity.

The closest wastewater disposal wells to the San Andreas Fault (SAF) are located in oilfields just over 10 km (6.2 mi) away in the southern San Joaquin Valley. It is unlikely that current wastewater injection in these wells would induce earthquakes on the fault. If in the future significantly higher-volume injection were to take place in or close to these existing oilfields, then it is plausible that the likelihood of inducing earthquakes on the SAF could increase.

The probability of inducing larger, hazardous earthquakes by wastewater disposal could likely be reduced by following protocols similar to those that have been developed for other types of injection operations, such as enhanced geothermal. Even though hydraulic fracturing itself rarely induces felt earthquakes, application of similar protocols could protect against potential worst-case outcomes resulting from these operations as well.

4.2. Introduction

Induced seismicity refers to seismic events caused by human activities, which can include injection of fluids into the subsurface. The vast majority of induced earthquakes that have been attributed to fluid injection were too small to be perceptible by humans. However, seismic events induced by fluid injection have on several occasions been felt at the ground surface, and in extremely rare cases have produced ground shaking large enough to cause damage. This chapter reviews the current state of knowledge about induced seismicity, and discusses the data and research that would be required to determine the potential for induced seismicity in California, including along the SAF. Measures to assess and, if necessary, to reduce the risk from induced seismicity are also discussed.

4.2.1. Chapter Structure

This introductory section provides a brief overview of the general characteristics of earthquakes and the basic cause of earthquakes induced by subsurface fluid injection, followed by a summary of observed cases of induced seismicity related to well stimulation activities. Section 4.3 first discusses the potential impacts of induced seismicity in terms of the risks of nuisance and structural damage caused by ground shaking, and then describes the mechanics of fluid-induced earthquakes and the characteristics of seismicity sequences related to well stimulation. Section 4.4 considers factors that could influence the potential for well stimulation in California to induce seismicity, and describes the studies needed to assess that potential. Suggested measures to lower the likelihood of induced earthquakes

occurring and hence reduce the risks are described in Section 4.5. Section 4.6 identifies gaps in the available data that presently limit our ability to evaluate induced seismicity in California, and then discusses potential actions to address those gaps. A summary of findings and conclusions are presented in Sections 4.7 and 4.8, respectively.

4.2.2. Natural and Induced Earthquakes

An earthquake is a seismic event that involves sudden slippage along an approximately planar fault or fracture in the Earth. This process occurs naturally as a result of stresses that build up owing to deformation within the Earth's crust and interior. The size of an earthquake depends primarily on the area of the patch on the fault that slips and the amount of relative displacement across the slip patch. Earthquake sizes range over many orders of magnitude. There are many more small events than large events; a decrease of one unit in the magnitude scale (see below and Appendix 4.A) corresponds roughly to a ten-fold increase in the number of events. As a result, the vast majority of earthquakes can only be detected by sensitive instruments. If, however, the slip area is sufficient to generate an earthquake larger than magnitude 2 to 3, the energy released during the event can generate seismic waves sufficient to produce ground motions that can be felt by humans, and larger events (usually about magnitude 5 and above) can in some cases cause structural damage. Over one million natural earthquakes of magnitude 2 or more occur worldwide every year (National Research Council (NRC), 2013).

As discussed in Appendix 4.A, several alternative magnitude scales are commonly used to express earthquake sizes. These employ different methods to compute magnitude, but all of the scales are roughly consistent with each other (within one-half magnitude unit) for earthquakes smaller than about magnitude 7. Henceforth in this report, we use published moment magnitudes, M_w. When discussing specific earthquakes for which M_w was not reported, we use the published magnitude, which, for the earthquakes discussed below, include only local magnitude, M_L and body-wave magnitude, m_b. In published cases when the scale was not specified, or to refer to magnitude in a general sense, we use the designation "M". Definition of the term "microseismicity" is somewhat arbitrary; for example, in earthquake seismology microseismicity usually refers to earthquakes smaller than M_w2-3, whereas in hydrofracture monitoring it commonly refers to events smaller than M_w0. In this report, we use microseismicity to describe earthquakes having magnitudes less than M_w3.

Earthquakes caused by human activity are termed *induced seismicity*. Activities that can induce earthquakes include underground mining, reservoir impoundment, and the injection and withdrawal of fluids as part of energy production activities (NRC, 2013). Note that some authors distinguish between "induced" and "triggered" events according to various criteria (e.g., McGarr et al., 2002; Baisch et al., 2009). In this report we do not make this distinction, but refer to all earthquakes that occur as a consequence of human activities as induced seismicity.

4.2.3. Induced Seismicity Related to Well Stimulation

Induced earthquakes related to well stimulation can be caused by injection of fluids into the subsurface, both for hydraulic fracturing stimulation itself and for disposal of recovered fluids and produced wastewater during stimulation and subsequent production. The predominant mechanism responsible for a fluid injection-induced earthquake is an increase in the pore-fluid pressure within a fault that reduces the confining stress that holds the two sides of the fault together, thus reducing its frictional resistance to slip (Hubbert and Rubey, 1959). Applying this mechanism to estimate the probability that seismic events of concern will be caused by a particular operation requires measurement or calculation of (1) the development of the subsurface pore-pressure perturbation in time and space, (2) characterization of faults likely to experience elevated pressures, and (3) characterization of rock material properties and *in situ* stress conditions. Because in practice these input parameters are often known only within broad bounds, an important part of the analysis is to properly constrain the uncertainties in order to correctly determine uncertainty bounds on the calculated event probabilities.

To date, the largest observed event attributed to hydraulic-fracture well stimulation is an M_L3.8 earthquake that occurred in the Horn River Basin, British Columbia, in 2011 (BC Oil and Gas Commission, 2012). The generally lower magnitudes of events associated with hydraulic fracturing relative to those induced by wastewater disposal are usually attributed to the short durations, smaller volumes, and flowback of injection fluids following stimulation, which result in smaller regions affected by elevated fluid pressures compared with the longer time periods and much higher volumes of wastewater injection. None of the events related to hydraulic fracturing reported in the literature have occurred in California and (with the possible exception of one paper that discusses an abnormal slow earthquake) we have found no published study that addressed this topic in California. If hydraulic fracturing operations carried out in California to date have, in fact, not induced normal seismic events above M2, possible explanations are that most of the well stimulation takes place in vertical wells at relatively shallow injection depths and employs relatively small injected volumes (Chapter 2). Volume I of this report concludes that salient features of hydraulic fracturing in California in the near- to mid-term are expected to be similar to those experienced thus far. If in the longer term hydraulic fracturing in the state shifts to larger injected volumes and deeper stimulation, then the likelihood of induced seismicity from hydrofracturing could increase.

The largest observed earthquake suspected to be related to wastewater disposal in the U.S. to date is a 2011 M_w5.7 event near Prague, Oklahoma (Keranen et al., 2013; Sumy et al., 2014), although the cause of this event is still under debate (Keller and Holland, 2013; McGarr, 2014). The largest earthquake clearly linked to stimulation-related wastewater injection is a 2011 M_w5.3 event in the Raton Basin of Colorado and New Mexico (Rubinstein et al., 2014). Despite decades of oil and gas production and wastewater injection, extensive seismic monitoring and exceptional in-depth research into

the occurrence and mechanics of regional and local earthquakes, there are no published reports of induced seismicity caused by wastewater disposal related to oil and gas operations in California. However, there has been no comprehensive, in-depth study of the relationship between seismicity and disposal operations in the state.

Typical wastewater volumes injected per well in California are generally less than those associated with well stimulation operations in other parts of the country where induced seismicity has occurred. For example, typical wastewater volumes injected in Kern County to date have been about one fourth of those resulting from well stimulation in the Barnett shale and injected in the Dallas-Fort Worth area in Texas, where induced seismicity has been reported from ongoing observational studies. This might suggest that at the present time the potential for induced seismicity related to wastewater disposal in California may be relatively low compared with some other regions in the U.S. However, because the possible relationship between injection and seismicity in California has yet to be investigated, the potential seismic impact is at present unknown. Expanded well stimulation activity would require disposal of larger volumes of fluid, which would potentially increase the impact. Given the active tectonic setting of California, it will be prudent to carry out an assessment of induced seismic hazard and risk as part of the permitting process for future injection projects, particularly in areas where there are active faults and that experience naturally occurring seismicity. A comprehensive study of spatial and temporal relationships between wastewater injection and seismicity is necessary to provide a basis for such assessments. The chance of inducing larger, hazardous earthquakes would most likely be reduced by following protocols similar to those that have been developed for other types of injection operations, such as those for enhanced geothermal energy production (e.g. Majer et al., 2012).

4.3. Potential Impacts of Induced Seismicity

Induced seismicity can produce felt or even damaging ground motions when large volumes of water are injected over long time periods into zones in or near potentially active earthquake sources. The relatively small fluid volumes and short time durations involved in most hydraulic fracturing operations themselves are generally not sufficient to create pore-pressure perturbations of large enough spatial extent to generate induced seismicity of concern. In contrast, earthquakes as large as M_w5.7 have been linked to injection of large volumes of wastewater into deep disposal wells in the eastern and central United States (Keranen et al., 2013; Sumy et al., 2014).

Seismic hazard is defined as the probability that a specific level of ground shaking will occur at a particular location during in a specified interval of time. This formal definition is a departure from the meaning of the more general term “hazard”, which refers to possible negative outcomes or impacts. In this chapter, the word hazard alone indicates the more general possibility of impact, while the term *seismic hazard* will be used to refer to the formal definition used by the seismic hazard community. *Seismic risk* is the probability of a consequence, such as deaths and injuries or a particular degree of building damage, resulting from the shaking. Risk, as defined with regard to seismic ground

motion, therefore combines the seismic hazard with the vulnerability of the population and built infrastructure to shaking, so that for the same seismic hazard, the risk is higher in densely populated areas. This use of the word risk is consistent with that used in other fields and involves both likelihood (probability of occurrence) and impact severity.

4.3.1. Building and Infrastructure Damage

Conventional seismic hazard and risk assessment deal with building and infrastructure damage—and the possible resulting injuries and loss of life—caused by strong ground shaking generated by naturally occurring earthquakes. The threshold magnitude for earthquakes to be capable of causing structural damage is generally considered to be about M_w5. Ground shaking from induced seismicity poses a potential incremental hazard above the natural background that needs to be considered in assessing the overall risk of an injection operation.

4.3.2. Nuisance from Seismic Ground Motion and Public Perception

Unlike assessing risk from naturally occurring seismicity, in the case of induced seismicity the likelihood of causing public nuisance from small events that are felt in nearby communities also has to be considered. This seismic risk includes minor cosmetic damage such as cracked plaster, as well as annoyance, alarm, and other adverse effects such as disrupted sleep. The magnitude threshold for felt events can be as low as M1.5–2.0 for the shallow depths of seismicity that are typically associated with fluid injection. In general, small earthquakes occur more frequently than large ones (see Section 4.2.2). Therefore, the frequency of occurrence of felt events can be relatively high, so that they may pose an ongoing impact on the quality of life in nearby communities.

4.3.3. Mechanics of Earthquakes Induced by Subsurface Fluid Injection

This section summarizes the physical mechanisms responsible for earthquakes induced by fluid injection. Fluid injection related to well stimulation takes place both for hydraulic fracturing and for wastewater disposal. In general, induced seismicity related to well stimulation is dominated by perturbations in fluid pore pressure, rather than by changes in *in situ* principal stresses (NRC, 2013). The characteristics of pore-pressure perturbations and induced seismicity resulting from hydraulic fracturing and wastewater disposal and their potential impacts are discussed in Sections 4.3.4 and 4.3.5, respectively.

During fluid injection there can be two types of rock failure, tensile and shear. Below we describe these two types of failure in the context of injection operations related to well stimulation.

4.3.3.1. Tensile Fracturing

The primary objective of hydraulic fracturing is to inject fluid into the earth to create a new fracture that connects the pores and existing fractures in the surrounding rock with the well, thus forming a permeable pathway that enables the oil and/or gas (and water) in the pores and fractures to be recovered. Hydraulic fractures are created by the rock failing in tension when the fluid pressure exceeds the *in situ* minimum principal stress (see Appendix 4.B). In this type of failure, a roughly planar fracture forms in the rock, and the walls of the fracture move apart perpendicular to the fracture plane at the same time as the fracture propagates (grows) at the crack tip in the direction parallel to the fracture plane. While there may be bursts of fracturing over short length scales at the crack tip, large-scale hydraulic fractures form slowly (hours) and can extend up to hundreds of meters away from the well. Although the physical processes at the crack tip are not yet fully understood, it appears that the amount of seismic energy radiated as the tensile fracture propagates is small and difficult to detect. Therefore, hydraulic fracture growth itself is responsible for little, if any, of the seismicity recorded in the field, and it probably makes little or no contribution to seismic hazard.

4.3.3.2. Shear Failure on Pre-existing Faults and Fractures

Shear failure on existing faults and fractures can occur both during stimulation by hydraulic fracturing and during wastewater disposal. During stimulation, shear events serve to enhance the permeability of small, existing fractures and faults and to link them up to create conductive networks connected to the main hydraulic fracture. Shear slip is the type of failure that occurs in most natural tectonic earthquakes, and it is shear events on larger faults that can produce perceptible or damaging ground motions at the Earth's surface.

During a shear event the two faces of the fault slip in opposite directions to each other parallel to the fault surface. The conditions for the initiation of shear slip are governed by the balance between the shear stress applied parallel to the fault surface, the cohesion across the fault, and the frictional resistance to sliding (shear strength). Assuming that the cohesion is negligible, these conditions are summarized in the Coulomb criterion,

$$\tau = \mu\,(\sigma - p) \qquad (4\text{-}1)$$

in which an applied shear stress (τ) is balanced by the shear strength, which is the product of the coefficient of friction (μ) and the difference between normal stress (σ) and pore-fluid pressure (p). Shear stress is directed along the fault plane, while normal stress is directed perpendicular to the plane. The quantity (σ - p) is called the effective stress. Effective stress represents the difference between the normal stress, which pushes the two sides of the fault together and increases the frictional strength, and the fluid pressure within the fault, which has the opposite effect. The Coulomb criterion states that slip will occur when the shear stress (τ) exceeds the strength of the fracture (right-hand

side of Equation 4-1). The shear stress that drives earthquake slip results from strain that accumulates in the Earth's crust, primarily as a result of tectonic and gravitational loading. An earthquake occurs when a fault fails in shear, releasing stored strain energy. In a tectonic earthquake, fault failure occurs when the accumulated shear stress reaches the critical value. Fault failure can also be initiated by decreasing the effective stress either by decreasing the normal stress (σ) that holds the fault closed and unable to slip, or by increasing the fluid pressure, which tends to push the sides of the fault apart, enabling slip.

4.3.3.3. Factors Influencing the Probability of Occurrence of Induced Earthquakes

If elevated pore pressures produced by either hydraulic fracturing or wastewater injection reach nearby faults or fractures, the resulting decrease in effective stress on the fault/fracture planes can cause induced seismicity. Therefore, in both activities, one consideration in developing an injection strategy should be to prevent the pressure perturbation from reaching larger faults capable of generating significant seismic events. This would help to minimize the seismic hazard and, in the case of well stimulation, to inhibit the fracture from propagating beyond the bounds of the hydrocarbon reservoir and providing a potential leakage pathway.

The primary factors that determine the probability of inducing seismic events are the volume of injected fluids, the spatial extent of the affected subsurface volume, ambient stress conditions, and the presence of faults that are well oriented for slip and are near-critically stressed (Appendix 4.B). The primary factors affecting the magnitude and extent, shape, and orientation of a pore-pressure perturbation include the injection rate and pressure, which are generally interdependent, the total volume injected, the hydraulic diffusivity (a measure of how fast a pore-pressure perturbation propagates in the fluids in the pore space), and the stress state and natural fracture orientation and conductivity under injection conditions. At early stages of an injection, the extent of the pressure perturbation depends on the hydraulic diffusivity and the duration of the injection, while the maximum pore pressure depends on the product of injection rate and duration divided by the permeability (NRC, 2013). At later stages, the induced pore-pressure field does not depend on the injection rate or permeability, but becomes proportional to the total volume of fluid injected.

4.3.3.4. Maximum Magnitude of Induced Earthquakes

The vast majority of earthquakes induced by fluid injection in general do not exceed M1 (e.g., Davies et al., 2013; Ellsworth, 2013). However, larger magnitude earthquakes ($M > 2$) have resulted from both wastewater injection and hydraulic fracturing. McGarr (2014) proposed estimating upper bounds on induced earthquake magnitudes based on net total injected fluid volume, observing that such a relationship is found to be valid for the largest induced earthquakes that have been attributed to fluid injection. Shapiro et al. (2011) proposed a similar approach to estimating maximum magnitude, based on the dimensions of the overpressurized zone deduced from observed microseismicity. Brodsky and Lajoie

(2013) also concluded that induced seismicity rates associated with the Salton Sea geothermal field correlate with net injected volume. However, the approaches proposed by both McGarr (2014) and Shapiro et al. (2011) appear to imply that fault rupture induced by the injection occurs only within the volume of pore-pressure increase. An alternative hypothesis is that a rupture that initiates on a fault patch within the overpressured volume can continue to propagate beyond its boundaries, in which case the possible maximum magnitude is determined by the size of the entire fault. Indeed, McGarr (2014) does not regard that his relationship determines an absolute physical limit on event size.

4.3.4. Induced Seismicity Resulting from Hydraulic Fracturing Operations

Because hydraulic fracture treatments are carried with relatively small injected volumes over short time periods and a proportion of the fluid flows back up the well following stimulation, the volume of the subsurface affected by pressure perturbations is usually confined within a few hundred meters of the wellbore, as shown by microseismic and tiltmeter fracture mapping results (e.g., Shemeta et al., 1994; Shapiro and Dinske, 2009; Davies et al., 2012; Fisher et al., 2002; Fisher et al., 2004). Davies et al. (2013) cite evidence to suggest that induced shear events in the vicinities of stimulation zones are mainly caused by fluids leaking off into preexisting faults and fractures intersected by the hydraulic fracture. Shear failure may also occur on nearby, favorably oriented faults and fractures isolated from the zone of increased pressure due to perturbation of the local stress field near the tip of the propagating hydraulic fracture (e.g., Rutledge and Phillips, 2003).

There can be a time delay between the beginning of injection and the occurrence of larger ($M > 2$) events, and in several cases the largest event has occurred after injection ceases. The longest time delay observed to date following a well stimulation injection was almost 24 hours before the occurrence of the largest (M_L3.8) event at the Horn River Basin, BC site (BC Oil and Gas Commission, 2012). A 2011 M_L2.3 earthquake in Blackpool, UK, occurred about 10 hours after injection ceased at the Preese Hall 1 stimulation well (de Pater and Baisch, 2011).

Overall, because of the relatively small volumes of rock that experience elevated pressures, there is a lower potential seismic hazard from short-duration hydraulic fracture operations than from disposal of large volumes of wastewater. The fact that, to date, the maximum magnitudes of events caused by hydraulic fracturing have been well below those usually considered to be capable of causing damage suggests that the likelihood of damaging events being induced by hydraulic fracturing is very low.

Published cases of known or suspected fluid injection-induced seismicity resulting from well stimulation and wastewater disposal that included events greater than M1.5 are described in Appendix 4.C. Five out of the six seismicity sequences listed in Table 4.C-1 attributed to hydraulic fracturing worldwide included felt earthquakes, and in all but one of these five cases, only one or two events were reported felt. This suggests that the risk of nuisance is also quite low. However, it is pertinent that all but one of the cases involving

felt earthquakes have occurred during the major upsurge in well stimulation activity since 2010, so that a further increase in activity in a particular region may increase the overall seismic hazard and risk there beyond past experience.

4.3.5. Induced Seismicity Resulting from Wastewater Disposal

Large-scale, continuous injection of wastewater into a single formation over time periods of months to years commonly generates overpressure fields of much larger extent than those resulting from well stimulation. For example, at the Rocky Mountain Arsenal, Colorado significant earthquakes caused by fluid injection occurred 10 km (6.2 mi) away from the injection well (Healy et al., 1968; Herrmann et al., 1981; Nicholson and Wesson, 1990). Hydrologic modeling of injection into the deep well at the site indicated that the seismicity tracked a critical pressure surface of 3.2 MPa (Hsieh and Bredehoeft, 1981). Long time delays between the cessation of injection and the occurrence of larger events have also been observed in several cases. For example, at the Rocky Mountain Arsenal, the largest earthquake (M_w4.8) occurred 17 months after injection ceased (Herrmann et al., 1981).

Generally, the likelihood of inducing larger events increases as the volume of injected wastewater increases. The largest earthquake suspected of being related to wastewater disposal is the 2011 M_w5.7 Prague, Oklahoma event (Keranen et al., 2013; Sumy et al., 2014), but the causal mechanism of this event is still the subject of active research, and the possibility that it was a natural tectonic earthquake cannot confidently be ruled out at present. The largest earthquake for which there is clear evidence for a causative link to stimulation-related wastewater injection is the 2011 M_w5.3 event in the Raton Basin of Colorado and New Mexico (Rubinstein et al., 2014). It is important to note, however, that significant induced seismicity has occurred at very few of the tens of thousands of wastewater disposal wells currently or formerly active in the U.S. (e.g., NRC, 2013; Ellsworth, 2013; Weingarten and Ge, 2014).

In most of the reported cases of induced seismicity associated with wastewater disposal listed in Table 4.C-1, events occurred both in the sedimentary formation into which the injection took place and, except in the Dallas-Fort Worth and Cleburne, Texas sequences, in the underlying crystalline basement rocks. In all of the cases, the seismicity illuminated planar features that were interpreted as favorably oriented faults reactivated by injection. Most of the faults interpreted from the seismicity had not been mapped on the ground surface. Reactivation of faults well below the injection interval can occur if there is hydraulic communication between them and the well (Horton, 2012; Justinic et al., 2013), and although the matrix permeability of basement rock is generally very low, critically stressed faults and fractures in this part of the brittle crust can serve as high permeability channels (Townend and Zoback, 2000; Fehler et al., 1998; Shapiro et al., 2003). The maximum depth of seismicity in the cases listed in Table 4.C-1 ranged from about 4 to 8 km (2.5 to 5 mi).

All seven of the M4 and larger earthquakes that occurred within the fluid injection-induced seismicity sequences listed in Table 4C-1 and that have relatively accurate hypocentral locations constrained by local seismic networks nucleated at depths between 3 and 6 km (1.9 and 3.7 mi). This depth range is assumed to correspond to the zone some distance below the injection interval where high fluid overpressures over relatively large fault areas coincide with stresses that put favorably oriented faults into a near-critical state; i.e. where the pressure reaches the critical value needed to nucleate a larger event. Deeper seismicity corresponds both to aftershocks of the larger events and to smaller magnitude events perhaps triggered at lower pressures.

Relatively high seismic hazard from earthquakes below M_w4.5 translates into a greater risk of nuisance if the seismicity occurs close to inhabited areas. Of the 14 events in Table 4.C-1 attributed to wastewater disposal, five were larger than M_w4.5. Only three of these, the M_w4.8 1967 Rocky Mountain Arsenal, the M_w5.7 2011 Prague, and the M_w5.3 2011 Raton Basin events, caused anything more significant than localized minor damage. However, as noted above, events as small as about M_w5 are generally considered to be capable of causing significant damage under certain circumstances (shallow focal depth, construction that is not seismically resistant, etc.), at least in the vicinity of the epicenter. Therefore, although it may be low in absolute terms, the seismic risk of damage associated with wastewater injection is relatively much greater than that associated with well stimulation. In view of the dramatic increase in seismicity—including all but one of the events greater than M_w4.5 in Table 4.C-1—that has accompanied the upswing in wastewater disposal in some parts of the U.S. beginning in 2010 (see U.S. Geological Survey, 2015), a future increase in the rate of operations in a particular region may increase the likelihood of damage there, as well as nuisance.

4.4. Potential for Induced Seismicity in California

All of the U.S. cases of induced seismicity related to fluid injection discussed in Appendix 4.C occurred within the continental interior, where tectonic deformation rates are very low. California, on the other hand, is situated within an active tectonic plate margin, where the rapid buildup of shear stress on the numerous active faults (Figure 4.4-1) results in much higher seismicity rates in many areas of the state than in the continental interior, as can be seen in Figure 4.4-2. If, as discussed in Appendix 4.B, the Earth's upper crust is generally in a near-critical stress state, then the high loading rates would imply that a relatively high proportion of faults in California will be close to failure at any given time, and hence susceptible to earthquakes triggered by small effective stress or shear stress perturbations.

4.4.1. California Faults and Stress Field

Unlike the central and eastern U.S., a large number of active faults have been mapped at the Earth's surface and characterized in California. Figures 4.4-1 and 4.4-2 show the surface traces of active faults in central and southern California contained in the U.S. Quaternary Fault and Fold (USQFF) database (http://pubs.usgs.gov/fs/2004/3033/fs-2004-3033.html). This database contains descriptions of faults known or believed to have been active during the Quaternary period (the last 1.6 million years). While particular attention should be paid to these faults in assessing the potential for induced seismicity and in siting injection operations, local faults that are suitably oriented for slip in the prevailing *in situ* stress field (see Appendix 4.B) also need to be taken into account, as does the possible presence of unmapped faults like the basement faults activated in some of the recent cases of mid-continent induced seismicity discussed above. This is further discussed in Section 4.6.3 below.

Figure 4.4-1 shows the relationship of faults to the higher-quality (quality A-C) stress measurements in central and southern California taken from the World Stress Map database (Heidbach et al., 2008), which is the most recent compilation of tectonic stress orientations, and in some cases the magnitudes of principal stress components. These measurements are derived from observations of wellbore breakouts, earthquake focal mechanisms, pressure and tiltmeter monitoring of hydraulic fractures, and geological strain indicators.

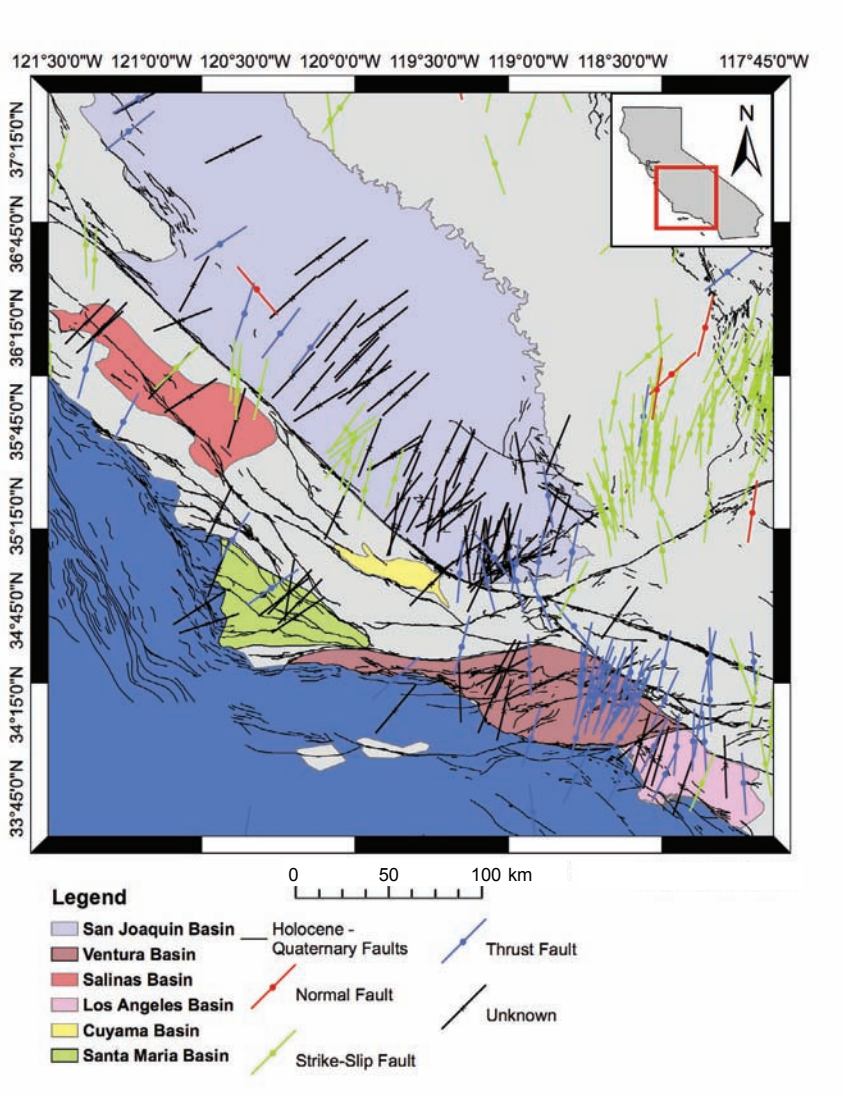


Figure 4.4-1. High-quality stress measurements for central and southern California from the World Stress Map (Heidbach et al., 2008), plotted with mapped faults from the USQFF database. The line plotted at the location of each stress measurement shows the orientation of the maximum horizontal compressive stress direction, color-coded according to stress regime.

4.4.2. California Seismicity

The generally low magnitude earthquake detection threshold in California, discussed in Appendix 4.A, means that California earthquake catalogs provide a relatively high-resolution picture of seismicity in the state as a whole. Figure 4.4-2 shows high-precision, relocated epicenters of California earthquakes M≥3 recorded in central and southern California between 1981 and 2011 contained in the Southern California Earthquake Data

Center (SCEDC) 2013 catalog (Hauksson et al., 2012). Intense seismicity occurs along segments of the major fault systems like the SAF zone in central California, in addition to relatively frequent (10s to 100s of years), large ($M_w \geq 6$) earthquakes. Large events accompanied by aftershock sequences have also occurred during this 30-year time period under the western slopes of the Central Valley near Coalinga (1983) and Kettleman Hills (1985), near Northridge (1994) and Whittier (1987, M5.9) north of Los Angeles, and along the coast near San Simeon (2003). Elsewhere, lower-magnitude seismicity is generally more diffuse. In addition to the Los Angeles Basin, oil-producing areas of the southernmost San Joaquin Valley and the Ventura Basin have relatively high rates of seismicity in the M2-5 range.

The vast majority of earthquakes in California are naturally occurring, but we can still question whether some of them may have been induced by fluid injection related to oil and gas recovery. The bulk of the seismicity that occurs in California is located at depths below about 2-3 km (1.2 – 1.9 mi). Therefore, the upper boundary of the main seismogenic zone is within about the same depth range as the deepest wastewater disposal wells for which depth information is available in the DOGGR (2014a) database, and about 1 km (0.6 mi) deeper than the depths of the wells having the highest cumulative injected volumes (see Section 4.4.3.1). Based just on the observed depths of earthquakes relative to injection depths in the reported cases of induced seismicity discussed in Section 4.3.5, it would appear that the overall potential for seismicity to be induced by wastewater injection may be at least as high in California as in the central U.S. Furthermore, some M5-6 events are observed to occur at relatively shallow depths in California, which suggests that induced earthquakes could be at least as large as those experienced to date in the continental interior. For example, ten (out of a total of 98) M5-6 earthquakes in the Hauksson et al. (2012) 1981–2011 catalog have focal depths between 3 and 6 km (1.9 and 3.7 mi), the depth range of M4 and larger induced events in the mid-continent (Section 4.3.5).

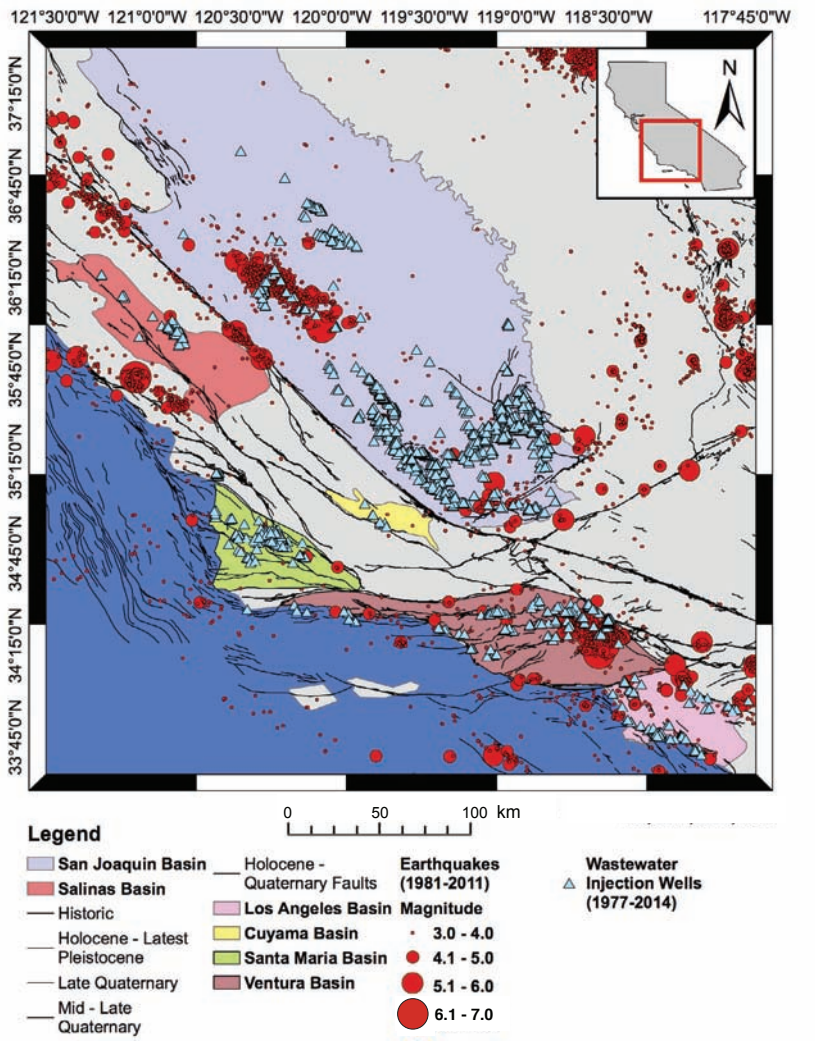


Figure 4.4-2. High-precision locations for earthquakes M≥3 in central and southern California during the period 1981-2011 (Hauksson et al., 2012), and active and previously active water disposal wells from DOGGR (2014a). Faults as in Figure 4.4-1.

While the above argument suggests that induced seismicity could potentially be caused by wastewater disposal in California, analysis of the relationship of seismicity to injection operations in the state is necessary to find out if that is indeed the case and, if so, to assess the resulting seismic hazard. Despite decades of injection in Californian oil and gas fields and one of the most active seismological monitoring and research programs in the world, no systematic study to explore possible associations between seismicity and fluid injection related to oil and gas production in the state has yet been completed. Although there have been numerous studies of induced seismicity associated with injection and production in geothermal fields in California (e.g., Eberhart-Phillips and Oppenheimer, 1984; Majer et

al., 2007; Kaven et al., 2014; Brodsky and Lajoie, 2013), and microseismic monitoring is routinely used to monitor hydraulic fracturing in oilfields (e.g., Murer et al., 2012; Cardno ENTRIX, 2012), we have found only one published paper (Kanamori and Hauksson, 1992) in which a California earthquake greater than M2 was linked to oilfield fluid injection. In that case, the authors attributed the occurrence of a very shallow M_L3.5 slow-slip event to hydraulic fracturing at the Orcutt oilfield in the Santa Maria Basin. This event was anomalous in that it radiated much lower energy at much lower dominant frequencies than normal earthquakes of similar size.

4.4.3. Correlation of Seismicity and Faulting with Injection Activity in California

One of the reasons that there have been no detailed studies of possible links between fluid injection in Californian oilfields and seismicity until recently is that small, naturally occurring earthquakes are very frequent in many regions of California, making it difficult to discriminate induced events in the M2-4 range from natural events (e.g., Brodsky and Lajoie, 2013). In contrast, natural seismicity rates are very low over most of the central and Eastern U.S., so if an earthquake does occur it is much easier to investigate whether the cause could be anthropogenic. However, Goebel et al. (2014) have reported initial results of a study that suggests that wastewater injection contributes to seismicity in Kern County, and Hauksson et al. (2014) have begun to study the relationship of seismicity to injection and production in the Los Angeles basin.

The most direct way to identify potential injection-induced seismicity on a statewide basis would be to conduct a comprehensive, systematic search for statistically significant spatial and temporal correlations between earthquake occurrence and injection rate, pressure, depth and distance from suitably oriented faults at a local scale within each oil-producing basin. A complete correlation analysis is beyond the scope of the present review. What this section does include is a summary of injection depths and volumes in California and an overview of the locations of injection wells relative to mapped faults and seismicity. Then a preliminary example of exploratory data analysis that seeks to identify relationships between injection and seismicity is presented. Given its generally higher potential for inducing seismicity of concern, we focus on wastewater disposal in California since 1981.

4.4.3.1. Depths and Volumes of California Wastewater Injection

The basic data required to carry out detailed correlation analyses include comprehensive records of the volume and pressure time histories and depths of injection in wastewater disposal wells in California. However, in the California Division of Oil, Gas and Geothermal Resources (DOGGR) database (DOGGR, 2014a), depth information is given for only 13% (329) of water disposal wells active since 1981. Reported depths range from 60 m (197 ft) to 4.42 km (14,500 ft). Of these, 21 currently active water disposal wells in their present configurations have recorded depths greater than 1.8 km (5,905 ft). The depth range for the ten highest-volume injection wells for which depth information is available is

732–838 m (2,400–2,750 ft). Compared with, for example, permitted injection intervals of 3.3–4.2 km (10,827–13,780 ft) in the Ellenberger Formation underlying the Barnett shale (Frohlich et al., 2010), the available data suggest that typical wastewater injection depths in California are about 1.5–3 km (4,921–9,842 ft) shallower than in Tarrant County in Texas, where the 2008–2009 Dallas-Fort Worth induced seismicity sequence occurred (see Appendix 4.C). However, this comparison is based on the very limited sample of California disposal wells for which depths are available.

Previous case studies show that the occurrence of induced earthquakes is usually closely associated with short-term changes in injection volume and pressure. Therefore, volume and pressure time histories sampled at intervals minutes to hours are ideally required to carry out detailed correlation analyses. However, volumes and pressures are reported on a monthly basis in the DOGGR database. The reported volume rates and pressures are assumed to be monthly averages.

Currently, average annual wastewater disposal volumes per well in California are generally less than in other regions in the U.S. where well stimulation is taking place. According to DOGGR (2010) (the most recent annual report available), total annual wastewater injected in 2009 in Kern County was approximately 79.4 million m^3 (21 billion gal) into 611 active wells, or an average disposal rate of about 360 m^3 (95,100 gal) per well per day. This, for example, is less than one-fourth of typical water disposal rates of 1,590 m^3 (420,000 gal) per well per day in Tarrant and Johnson Counties, Texas (Frohlich et al., 2010). In the Raton Basin of Colorado and New Mexico, an increase in the average daily rate of fluid injection to 300 m^3 /day (79,250 gal/day) per well, comparable to California's average daily disposal rate, was linked to a significant increase in the number of earthquakes greater than M3 (Rubenstein et al., 2014) (see Appendix 4.C), but in this case the increase in injection rate took place simultaneously in 21 wells within the basin.

In terms of cumulative volume, there are 27 wells in California that have cumulative injected volumes since 1977 greater than 16 million m^3 (4.2 billion gal), 13 of which are located on the eastern side of the southern San Joaquin Valley near Bakersfield. Further investigation is needed to determine if these 13 high-volume wells were injecting into the same pool. If this is the case, and if the wastewater was not injected into the same interval as it was produced from, then the aggregate injected volume into the pool between 1977 and 2013 was 334 million m^3 (88.2 billion gal). This is only one-half the aggregate injected volume reported for the Raton Basin during the main period of induced seismicity there between 2006 and 2013, when the 21 injection wells each disposed of 33 million m^3 (8.7 billion gal) (Rubenstein et al., 2014). The reported aggregate volume for the Raton Basin does not include the volume injected between 1995 and 2006, when the field was under development.

4.4.3.2. Locations of Wastewater Injection Wells Relative to Mapped Faults and Seismicity

Many active faults in California are not confined to the basement or deeper sedimentary layers but extend all the way to the Earth's surface. This means that in many cases the lateral distance from a disposal well to a fault is likely as important as the depth of injection in determining whether a hydraulic connection is established that allows injection-induced pressure changes to reach the fault. Although cases like the Rocky Mountain Arsenal and Raton Basin indicate that pressure perturbations large enough to induce earthquakes can travel distances up to10 km (6.2 mi) or more along fault zones, in all but one of the cases of mid-continent induced seismicity discussed in Section 4.3.5 the injection wells were located less than 3 km (1.9 mi) laterally from the fault defined by the seismicity. The exception was Paradox Valley, Colorado, where the largest event (M_w4.0 in January, 2013) induced by 17 years of continuous high-rate injection occurred on a fault located 8 km (5 mi) away from the well (Block et al., 2014). The cumulative volume injected in the Paradox Valley well between 1996 and 2012 was about 8.5 million m^3 (2.2 billion gal), about half of typical cumulative volumes injected into the 27 highest-volume wastewater disposal wells in California since 1977. It is important to note that there is a high-permeability pathway between the Paradox Valley well and the fault activated in the 2013 event, which apparently corresponds to a regional-scale fracture zone (King et al., 2014).

These well-fault distances provide the context for the following brief summary of spatial relationships between wastewater injections wells and surface faults and seismicity in oil-producing basins in California.

Figure 4.4-3 summarizes the distribution of distances between wastewater disposal wells active since 1981 and faults in the USQFF database in six oil-producing basins in California. Across all six basins, over 1,000 wells are located within 2.5 km (1.5 mi) of a mapped active fault, and more than 150 within 200 m (656 ft).

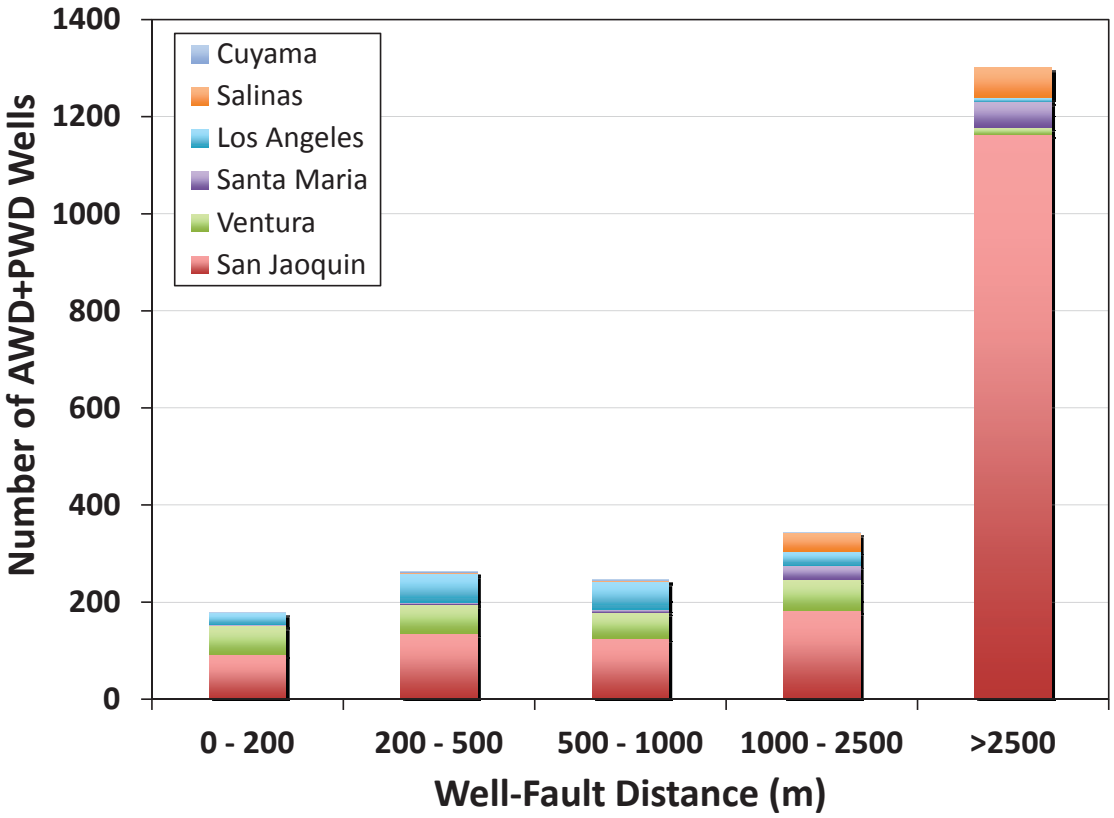


Figure 4.4-3. Distribution of distances between wastewater disposal wells active during the period 1981-present (DOGGR, 2014a) and Quaternary active faults in the six major oil-producing basins in California.

The maps in Figures 4.4-4 to 4.4-9 show the locations of disposal wells relative to mapped faults and seismicity in four of the largest oil-producing basins. The faults are colored according to the estimated time of their last earthquake activity as follows: historic (red), <~150 years; Holocene/latest Pleistocene (orange), <15,000 years; latest-Quaternary (yellow), <130,000 years; Quaternary (blue), <1.6 million years. The most recently active faults and those with the highest long-term slip rates are considered to be the ones most likely to experience future earthquakes. Long-term slip rates of California faults range from less than 0.1 mm/yr to 34 mm/yr on the SAF.

The historically active trace of the White Wolf fault (slip rate 2 mm/yr) delineates the southeastern boundary of the San Joaquin Valley (Figures 4.4-4 and 4.4-5). This fault last ruptured in the 1952 M7.3 Kern County earthquake. (Other red traces on Figures 4.4-5 and 4.4-6 are ground fractures mapped following the 1952 earthquake or have been linked to oilfield subsidence, and so they might not correspond to active faults.) The closest well to the White Wolf fault is about 5 km (3.1 mi) south the surface trace (Figure 4.4-5). The densest concentration of seismicity is located to the southwest, where two

Quaternary faults continue the trend of the historic White Wolf trace, and Holocene and Quaternary traces of the Pleito fault system are also mapped. In addition to abundant microseismicity, M4.7 and M5.1 earthquakes occurred in this area in 2005. Several injection wells are located within 1 km (0.6 mi) of a Quaternary strand of the Pleito system. Clusters of microearthquakes have occurred close to several of the injection wells in this area, but others are located away from the wells.

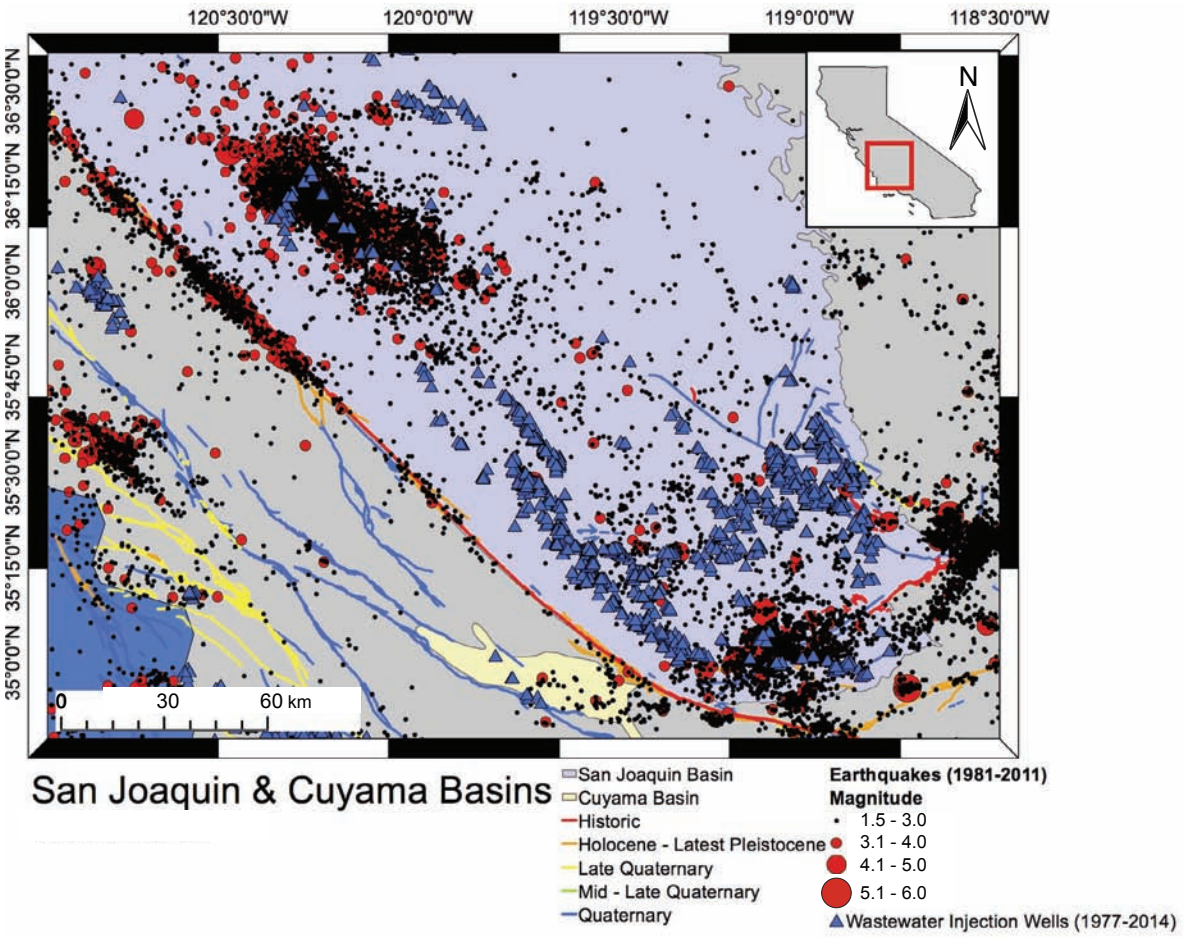


Figure 4.4-4. Earthquakes M≥1.5 in the southern San Joaquin Valley and Cuyama Basin from Hauksson et al. 2012, plotted with active and previously active water disposal wells from DOGGR (2014a) and faults from the USQFF database. Faults colored according to the time of most recent activity. The White Wolf fault is the red trace in the southeast corner of the Valley.

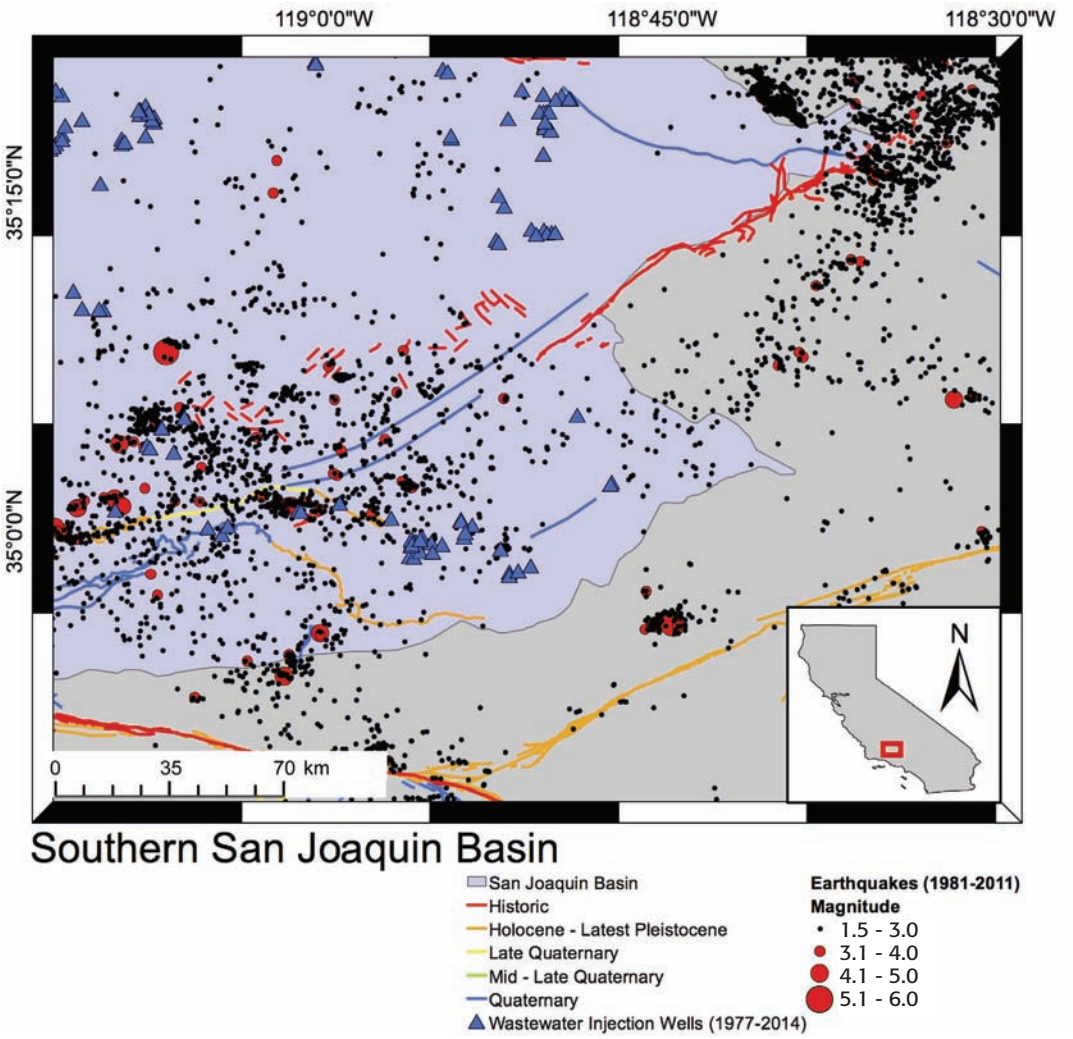


Figure 4.4-5. Earthquakes M≥1.5 in the southernmost San Joaquin Valley from Hauksson et al. (2012). Wells and faults as in Figure 4.4-4.

Quaternary and latest-Quaternary faults are mapped at the surface near the dense concentrations of disposal wells towards the eastern margin of the San Joaquin Valley in the vicinity of Bakersfield (Figure 4.4-6). Many of the Quaternary faults strike roughly north-south and are not favorably oriented for reactivation within the prevailing stress field (Figure 4.4-1). The green triangles show the locations of 13 of the 27 disposal wells in California having cumulative injected volumes greater than 16 million m^3 (4.2 billion gal). Earthquakes are observed only infrequently in this area. There is also only sparse, scattered seismicity near the long chain of disposal wells along the southwestern margin of the San Joaquin Valley (Figure 4.4-4). Most of the earthquakes in the dense cluster further northwest are aftershocks of M_w6.5 and M_w6.1 earthquakes that occurred in 1983 and 1985, respectively on deeply buried (blind) faults (U.S. Geological Survey, 1990; Ekström et al., 1992).

In the Santa Maria Basin, numerous wastewater disposal wells are located within 1–2 km (0.6–1.2 mi) of the surface traces of favorably oriented northwest-striking latest-Quaternary and Quaternary fault systems (Figure 4.4-7). All of the faults close to oilfields in the Santa Maria Basin have estimated slip rates less than 1 mm/yr (see California Geological Survey, 1996). The only dense cluster of seismicity is in the vicinity of the group of wells in the east-central part of the basin located in the Zaca oilfield. This cluster is discussed in Section 4.4.3.3 below. Numerous disposal wells in the Ventura Basin are sited very close to mapped Holocene-active faults, most notably along the major, west-striking Holocene San Cayetano system (slip rate 6 mm/yr) in the northern part of the basin, and to latest-Quaternary faults (Figure 4.4-8). Pockets of dense seismicity are located both close to and remote from injection wells. Most of the events in the dense cloud of seismicity at the eastern end of the basin are aftershocks of the deep (21 km; 13 mi) 1994 Northridge earthquake.

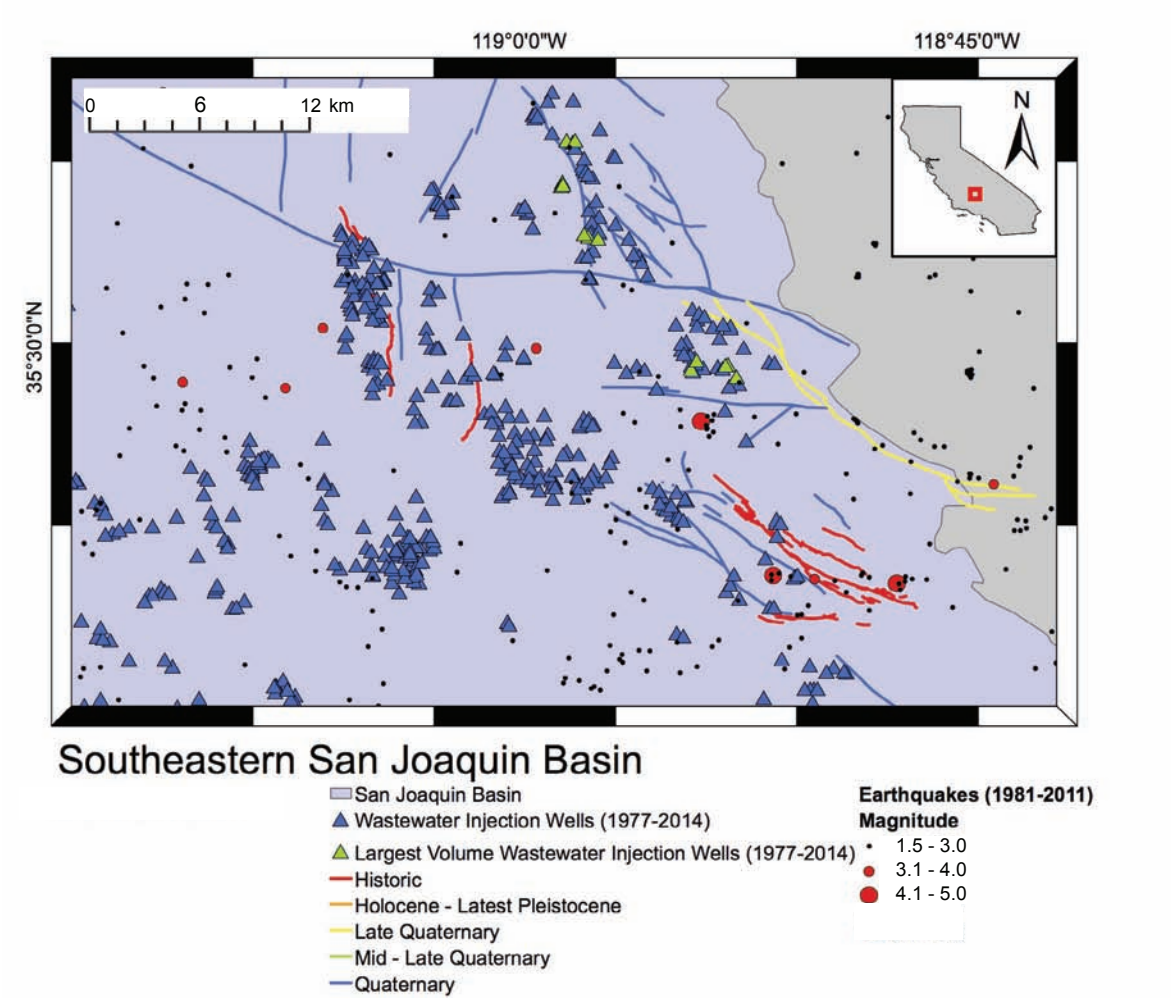


Figure 4.4-6. Earthquakes M≥1.5 in the southeastern San Joaquin Valley near Bakersfield from Hauksson et al. (2012). Wells having cumulative injected wastewater volumes >16 million m³

(4.2 billion gal) shown in green. Other wells and faults as in Figure 4.4-4.

In the Los Angeles Basin (Figure 4.4-9), disposal wells are concentrated mainly in oilfields located along the Holocene Newport-Inglewood fault zone (slip rate 1.5 mm/yr), a segment of which was the source of the destructive 1933 M_w6.4 Long Beach earthquake, and in the Wilmington oilfield. Several wells in the Wilmington field are located within 4 km (2.5 mi) of the Holocene Palos Verdes fault (slip rate 3 mm/yr). Only scattered seismicity has occurred near any these fields except Inglewood and Cheviot Hills at the northwestern end of the Newport-Inglewood trend. As in the Ventura Basin, clusters of seismicity are located close to some disposal wells but also elsewhere. The cluster at the top-center of the figure are aftershocks of the 2014 La Habra earthquake.

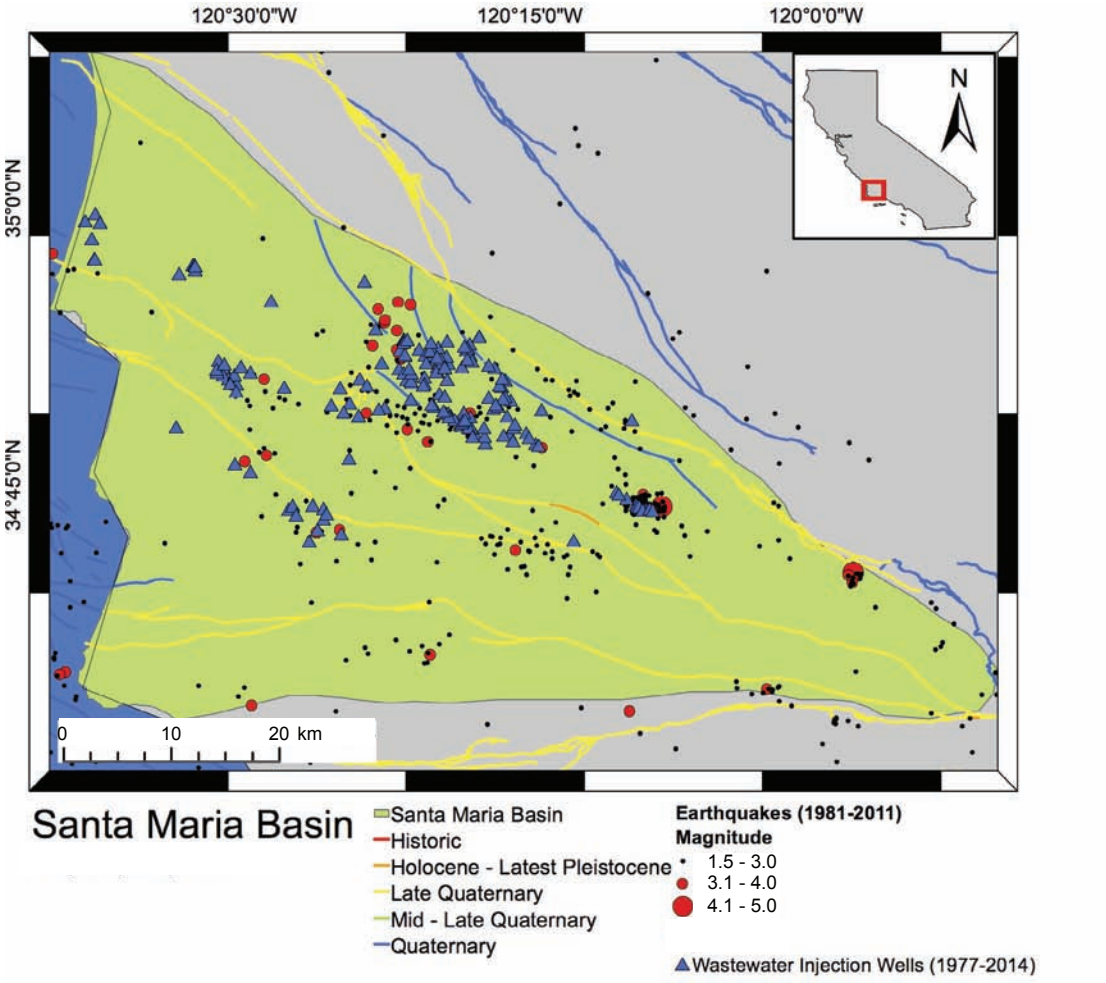


Figure 4.4-7. Earthquakes M≥1.5 in the Santa Maria Basin from Hauksson et al. (2012). Wells and faults as in Figure 4.4-4.

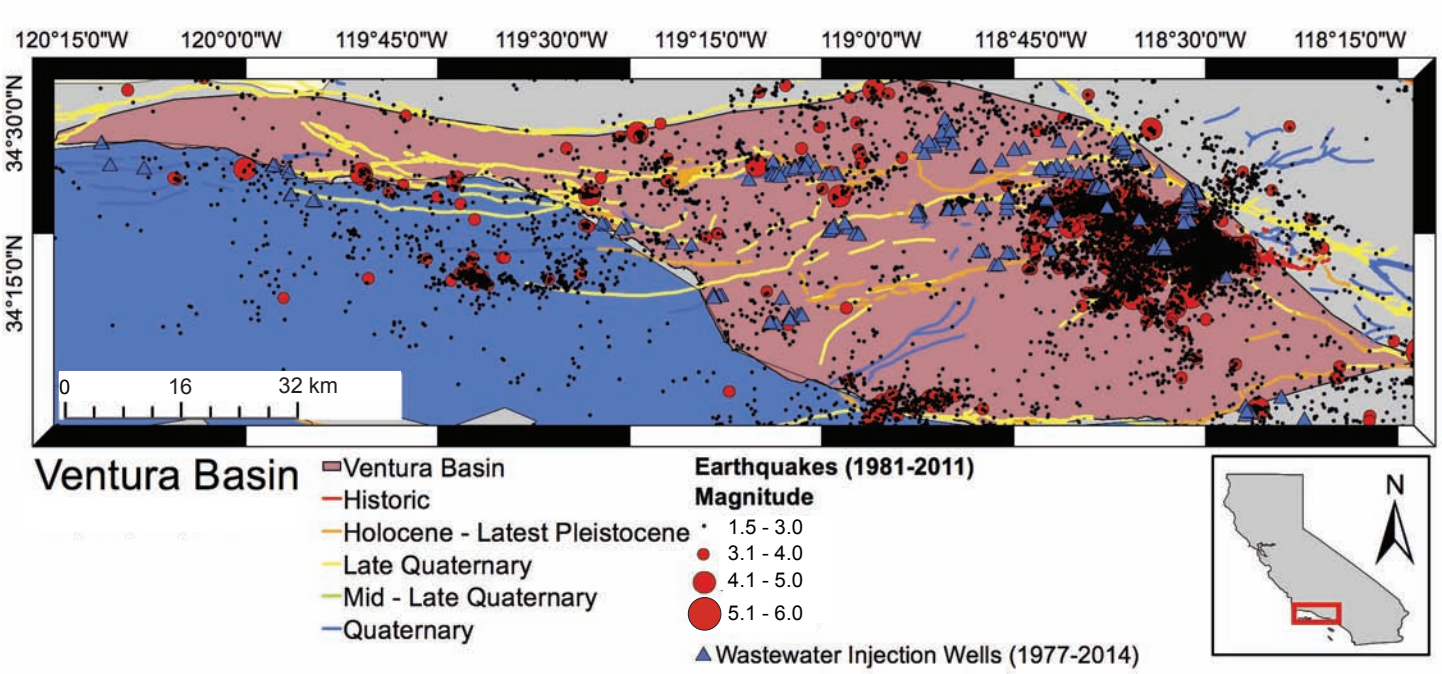


Figure 4.4-8. Earthquakes M≥1.5 in the Ventura Basin from Hauksson et al. (2012). Wells and faults as in Figure 4.4-4.

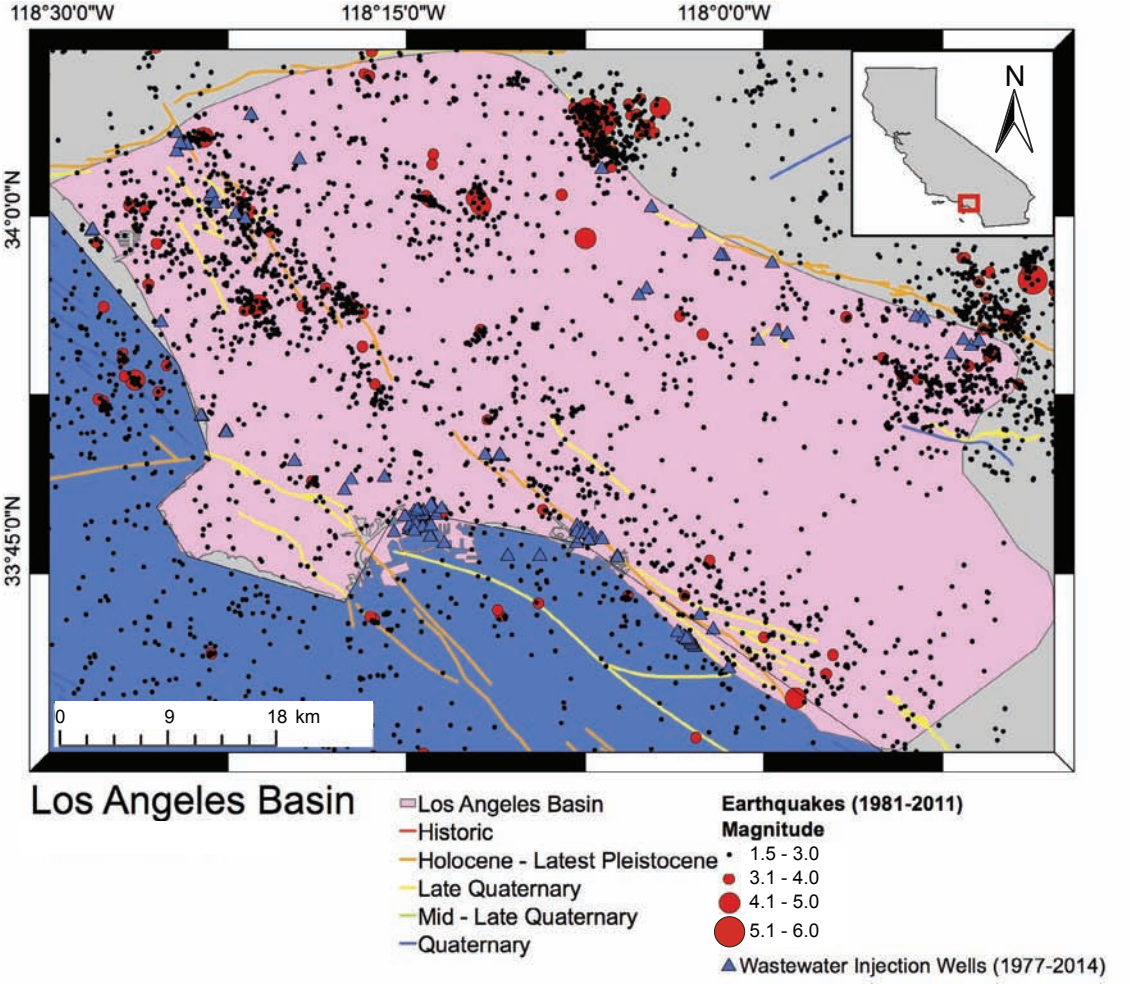


Figure 4.4-9. Earthquakes M≥1.5 in the Los Angeles Basin from Hauksson et al. (2012). Wells and faults as in Figure 4.4-4.

While numerous disposal wells in some of the basins are located very close to active faults, not all of those necessarily have the potential for inducing seismicity. In some cases injection may be into a depleted zone, in which years of oil production has reduced the pressure below its pre-drilling state, thus increasing the resistance to slip on faults in hydraulic connection with the reservoir (NRC, 2013). (Note that disposal into depleted reservoirs is distinct from reinjection of wastewater for enhanced oil recovery by water flooding; waterflood wells are listed separately in the DOGGR database.) In these cases, the potential for induced seismicity will not exist until the pressure buildup resulting from injection exceeds the original reservoir pressure. The DOGGR Online Well Record Search (DOGGR, 2014b) tool details the pool(s) into which each disposal well injects, so it should be possible to determine which wells inject into depleted zones by examining the production records for the same pool.

4.4.3.3. Preliminary Example of a Spatiotemporal Correlation Analysis

To analyze potential correlations of seismicity with water injection, we first identify clusters of earthquakes and then examine the relationships of the clusters to injection volumes and pressures. This is illustrated for the Santa Maria Basin in Figure 4.4-10. Figure 4.4-10a shows 1981–2011 Santa Maria Basin earthquake epicenters in the Hauksson (2012) catalog. To easily identify event clusters, each epicenter is color coded according to the slant distance (i.e., including event depth) of the event hypocenter to its nearest neighbor. Figure 4.4-10b shows the highly clustered seismicity contained in the green rectangle in 4.4.10a at expanded scale and the spatial relationship of the events to the locations of injection wells in the Zaca oilfield. Figures 4.4-10c and 4.4-10d compare the occurrence history of these 66 earthquakes with injected fluid volume and pressure histories for the four injection wells shown colored in Figure 4.4-10b. All of the events occurred between October 1984 and March 1987, and all but a few are clustered in two bursts of activity in October 1984 and October-November 1986. Both bursts include one event greater than M4.

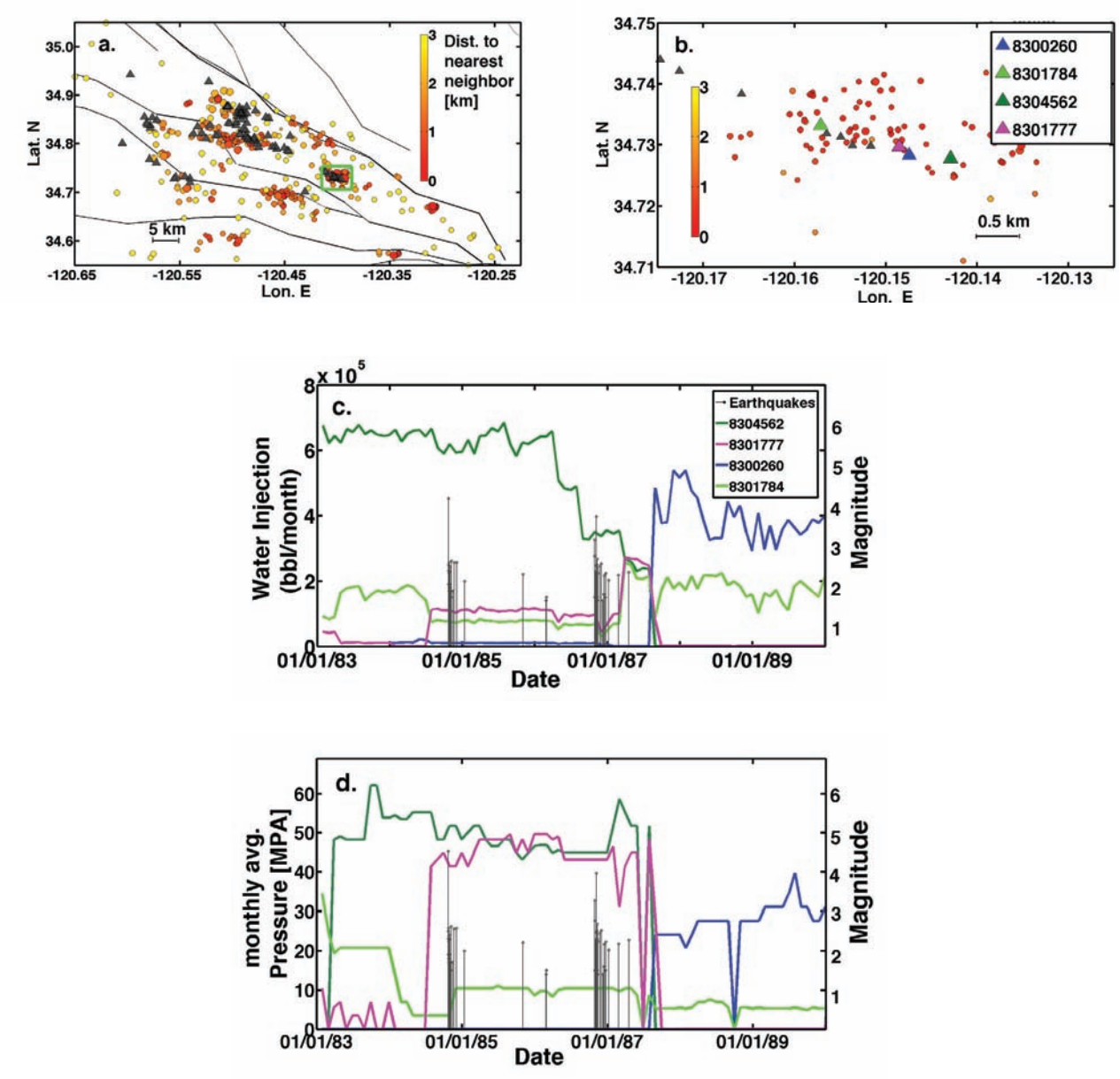


Figure 4.4-10. Spatiotemporal analysis of a seismicity cluster in the Santa Maria Basin. Earthquakes shown by solid circles in a and b are color-coded to show their closest slant distances to neighboring events. Wastewater injection wells are shown as triangles. Events and wells within the green rectangle in a are shown in b. Monthly injected volumes and wellhead pressure taken from the DOGGR (2014a) database for the four wells colored in b and identified by API number are plotted in c and d, respectively, along with the earthquakes in b shown in black.

The first burst of seismicity occurred about one month after the pressure in well 8301777 (magenta) reached its first peak following the abrupt increase in injection rate and pressure that began in June 1984, and also coincides with the beginning of a modest increase in pressure in well 8301784 (light green). These correlations suggest a relationship between the event sequence and the combined effect of the pressure increases in these two wells, which are the wells closest to the most densely clustered seismicity in Figure 4.4-10b. The second burst of activity was not associated with pressure changes apparent in the DOGGR database, but occurred shortly after a major decrease in injection rate in well 8304562 (dark green). In this case, no immediate correlation with changes in pressure in any of the wells is evident. However, all 66 earthquakes occurred during a period when the pressures in wells 8301777 and 8301784 (and also in well 8304562) were high, which further suggests a relationship between local seismicity and elevated fluid pressure. These evident relationships merit further detailed analysis that includes tests of statistical significance to investigate whether there is a causal link between the seismicity and pressure changes. Note that the flat portions of the pressure histories for the three wells mentioned above between May and December 1986 suggest missing data for this period, so that the pressure increase in well 8304562 (and in 8300260) evident after December 1986 may have begun earlier, perhaps following a pressure decrease sometime after May 1986.

This simple example demonstrates that analysis of the spatial and temporal relationship of earthquakes to wastewater injection has the potential to detect and characterize induced seismicity in California. However, the apparent gaps in the pressure data for several periods evident in Figure 4.4-10d, and the lack of depth information for any of the disposal wells in the Zaca field, illustrate two of the deficiencies in the present DOGGR well database that impede this kind of correlation analysis (see Section 4.6.1 below).

4.4.4. Potential for Induced Seismicity on the San Andreas Fault

The existing oilfields and disposal wells closest to the SAF are located just over 10 km (6.2 mi) away along the western margin of in the San Joaquin Valley (Figure 4.4-4). This is significantly greater than typical lateral well-fault distances of less than 3 km (1.9 mi) for the fluid injection-induced seismicity cases observed in the continental interior (see Section 4.4.3.2). It is similar to the 8 km (5 mi) distance between the Paradox Valley injection well and the fault that was the source of the 2013 M_w4.0 earthquake, but in that case a high-permeability pathway connects the well to the fault (Section 4.4.3.2). Therefore, while the possibility that current, relatively low-volume, wastewater injection in the San Joaquin Valley could induce earthquakes on the SAF cannot be entirely discounted, we judge that that it is unlikely.

Using the Paradox Valley case as a benchmark, it is plausible that the likelihood of triggering earthquakes on the SAF could increase if future high-volume wastewater injection took place in or close to existing disposal wells along the western margin of the San Joaquin Valley. Future injection projects that could potentially alter fluid pressures in the SAF or the other most active (high slip rate), major fault zones should

be subject to particularly rigorous screening and permitting procedures, as described in the following section.

4.5. Impact Mitigation

Even if a comprehensive investigation of the relationship of seismicity to oilfield injection were to conclude that the overall potential for induced seismicity in California is low, it would be prudent to adopt measures to mitigate the risks from induced seismicity that may be associated with new stimulation-related injection projects. It will be particularly important to adopt such measures if there is an increase in stimulation activity and expanded production, resulting in higher per-well volumes of injected wastewater approaching those employed elsewhere in the U.S. In this section, we discuss measures that should be considered before injection begins to reduce the likelihood of induced earthquakes, and to manage seismicity during and following injection.

Initial, low-level hazard and risk assessment during site screening could be used to place each site into one of a few risk categories (e.g., low, moderate, high), based on the following recommended criteria:

- Planned injection rate, cumulative volume, duration, and depth.
- Distance from active or potentially active faults, and recency and rate of fault activity.
- Existence of potential high-permeability pathways between the well and faults
- Estimation of pressure changes on nearby faults.
- Background seismicity.
- Proximity to population centers and critical facilities.

Decisions regarding permitting and regulation of a site in one of the higher risk categories could then be based on a level of probabilistic seismic hazard and risk assessment determined to be appropriate for that category. The final permit would specify operating parameters such as maximum injection rate and pressure adjusted to achieve an acceptable level of risk. An important part of the permit would be specifications for monitoring requirements and operating procedures to manage and, if necessary, mitigate induced seismicity during injection, and perhaps for a period after the well is shut down. Methods for induced seismicity hazard and risk assessment and management are discussed in Section 4.5.1 below.

If future large-volume wastewater disposal were to be planned at sites along the western margin of the San Joaquin Valley, and especially if new injection locations closer to the SAF and other major active faults were contemplated, these wells should be subject to the most stringent risk assessment and permitting requirements. These should include

detailed modeling to estimate the probability that the pressure changes on the fault over time would remain below a predetermined, conservative maximum bound.

4.5.1. Induced Seismic Hazard and Risk Assessment

Maps of seismic hazard from naturally occurring earthquakes in California are developed by the U.S. Geological Survey (USGS) and California Geological survey (CGS) as part of the National Seismic Hazard Mapping Project. The hazard maps and technical details of how they are produced can be found at http://earthquake.usgs.gov/hazards/index.php. Of the areas in which water disposal wells are currently active, seismic hazard from naturally occurring earthquakes is high in the Los Angeles, Ventura, Santa Maria, Salinas and Cuyama Basins and in the Santa Clarita Valley, and moderate to high along the western and southern flanks of the southern San Joaquin Valley. The hazard is moderate in the Bakersfield area and decreases towards the center and north of the San Joaquin Valley.[1]

Approaches to assessing induced seismicity hazard can be developed by adapting standard probabilistic seismic hazard assessment (PSHA) methods, such as those used by the USGS and CGS. The standard methods cannot be applied directly, however, because conventional PSHA usually is based only on mean long-term (100s to 1,000s of years) earthquake occurrence rates; i.e., earthquake occurrence is assumed to be time-independent. Induced seismicity, on the other hand, is strongly time- and space-dependent because it is dependent on the evolution of the pore pressure field, which must therefore be considered in estimating earthquake frequencies and spatial distributions.

Developing a rigorous PSHA method for short- and long-term hazards from induced seismicity presents a significant challenge. In particular, no satisfactory method of calculating the hazard at the planning and regulatory phases of a project is available at the present time; whereas in conventional PSHA earthquake frequency-magnitude statistics for a given region are derived from the record of past earthquakes, obviously no record of induced seismicity can exist prior to well stimulation or wastewater disposal. Using seismicity observed at an assumed "analog" site as a proxy (e.g., Cladouhos et al., 2012) would not appear to be a satisfactory approach, as induced seismicity is in general highly dependent on site-specific subsurface structure and rock properties.

1. Moderate and high seismic hazard are defined here as a 2% probability of exceeding peak ground accelerations of 0.1-0.3g and greater than 0.3g, respectively, in 50 years, where g is the acceleration due to gravity. The threshold of damaging ground motion is about 0.1g.

Physics-based approaches to generate simulated catalogs of induced seismicity at a given site for prescribed sets of injection parameters are under development (e.g., Foxall et al., 2013). Such approaches rely on adequate characterization of the site geology, hydrogeology, stress, and material properties, which are inevitably subject to significant uncertainties. However, large uncertainties in input parameters are inherent in PSHA in general, and techniques for propagating them to provide rigorous estimates of the uncertainty in the final hazard have been developed (e.g. Budnitz et al., 1997).

There has been more progress in developing methods for short-term hazard forecasting based on automated, near-real time empirical analysis of microseismicity recorded by a locally deployed seismic network once injection is under way (e.g., Bachmann et al., 2011; Mena et al., 2013; Shapiro et al., 2007). Continuously updated hazard assessments can form the input to a real-time mitigation procedure (Bachmann et al., 2011; Mena et al., 2013), as outlined in Section 4.5.2. Using two different time-dependent empirical models, Bachmann et al. (2011) and Mena et al. (2013) retrospectively were able to obtain acceptable overall fits of forecast to observed seismicity rates induced by the 2006 Enhanced Geothermal System (EGS) injection in Basel, Switzerland, over time periods ranging from 6 hours to 2 weeks. However, the models performed relatively poorly in forecasting the occurrence of the largest event (M_L3.4), which occurred after well shut-in; this event was forecast with a probability of only 15%, and the forecast probability of exceeding the ground motion it produced was calculated at only 5%. The performance of this empirical method could probably be improved by incorporating a more physically based dependence on injection rate or pressure.

4.5.2. Protocols and Best Practices to Reduce the Impact of Induced Seismicity

In 2004, the U.S. Department of Energy (DOE) and the International Energy Agency (IEA) sponsored an effort to develop a protocol and best practices to monitor, analyze, and manage induced seismicity at geothermal projects (Majer et al., 2007; 2012; 2014). The protocols/best practices are not intended to be either regulatory documents or universally prescribed sets of procedures for induced seismicity management, but rather to serve as a guide to enable stakeholders to tailor operating procedures to specific projects. Many geothermal operators in the western U.S. are implementing either all or parts of the most recent U.S. DOE protocol (Majer et al., 2012), and the U.S. Bureau of Land Management (BLM) has adopted it as the basis for developing criteria for geothermal project permitting on the federal lands administered by them.

Largely spurred by the dramatic increase in seismicity in the mid-continent discussed in Appendix 4.C, oil-producing states and the petroleum industry are beginning to develop similar protocols, such as those being developed by the Oklahoma Geological Survey and by a consortium of member companies in the American Exploration and Production Council (AXPC) (see Appendix 4.D). Zoback (2012) also describes a series of mitigation steps that operators could use as a guide. All of the protocols currently under development contain, in some combination, the steps that comprise the U.S. DOE geothermal protocol,

described in Appendix 4.D.

Current real-time induced seismicity monitoring and mitigation strategies used by most enhanced geothermal system (EGS) operators employ a "traffic-light" system similar to the one implemented by Bommer et al. (2006). The traffic-light system may incorporate up to four stages of near-real time response to recorded seismicity, ranging from normal operation (green) to bleeding off to minimum wellhead pressure and shutting down the well (red). The response trigger criteria are generally based on some combination of maximum observed magnitude, measured peak ground velocity and public response, although definition of the criteria is usually somewhat ad hoc and depends on the project scenario. The traffic-light procedure implemented at the 2006 Basel EGS project was not successful in preventing the occurrence of the M_L3.4 earthquake that led to the eventual abandonment of the project, even though the well was shut down following an earlier M_L2.7 event. The EGS community is beginning development of traffic-light methods that employ near-real time hazard updating like that reported by Bachmann et al. (2011) and Mena et al. (2013). These will provide risk-based forecasting based on the evolving seismicity and state of the reservoir to inform decision-making.

4.6. Data Gaps

4.6.1. Injection Data

There are two important gaps in the current DOGGR (2014a) injection database that seriously limit its usefulness for investigating induced seismicity in California. First, injection rates and wellhead pressures are reported monthly. These are presumably monthly averages, since water disposal rates and pressures are rarely constant over month-long intervals. Significant short-term variations in peak pressures and injection rates are relevant to detecting the effects of fluid injection on seismicity in the vicinity of the well, in addition to long-term rates and cumulative volumes that can potentially impact seismicity on more distant faults. Therefore, monthly averages are usually too coarse to carry out correlation analyses against incremental increases in seismicity above the high seismic background in many areas of California.

The second data gap is consistent and accurate reporting of injection depth and geological interval. Currently, depth information of any kind is provided for less than 15% of active and plugged wastewater disposal wells in the database. Furthermore, currently available information is ambiguous because the parameter "WellDepthAmount" in the database can refer to injection depth, top or bottom of the perforation interval, or the total vertical depth of the well. Correlating injection depth with stratigraphy and the depth of seismicity has been shown to be critical in identifying induced events (e.g., Keranen et al., 2013).

Although it may be feasible to conduct spatiotemporal correlation analyses to identify and provide a basic characterization of more prominent cases of potentially induced seismicity using the current DOGGR (2014a) database, filling these two data gaps to some extent in

the existing catalog would permit a much more comprehensive analysis. More complete reporting in the future would enable risk assessment and mitigation of induced seismicity for new stimulation-related injection operations.

4.6.2. Seismic Catalog Completeness

Although only earthquakes greater than about M2 are generally relevant to seismic hazard, M1 or even smaller earthquakes are important in analyzing potential induced seismicity. As discussed in Appendix 4.A, the estimated minimum magnitude of complete detection (M_c) of the USGS Advanced National Seismic System (ANSS) network is M1 or less in large areas of California, and less than M2 over most of the state. However, Figure 4A-1 shows that M_c is between 2 and 2.5 in the interior of the southern San Joaquin Valley and at some locations along the coast of southern California. Estimated mean, minimum and maximum M_c values in the main onshore oil-producing basins are summarized in Table 4.6-1; note that these values have not been adjusted to account for the tendency of the calculation method employed to underestimate M_c (see Appendix 4.A). Some wells in the southern San Joaquin Valley and the Los Angles and Ventura Basins are within areas having M_c2 or greater, so that microseismicity that may have been induced by injection into those wells might not have been recorded.

Ideally, a sensitive local seismic network comprising five or more seismic recording stations deployed at a spacing on the order of one kilometer or less is required to provide an adequate characterization of both the background activity and any induced seismicity at an injection site. Deploying sensors in deep boreholes is relatively expensive, but greatly enhances the signal-to-noise ratio, enabling very small earthquakes (often $M < 0$) to be recorded. While installation of a local network may not be feasible or necessary at many injection sites, it should be considered for sites in higher risk categories (Section 4.5).

4.6.3. Fault Detection

The USQFF fault inventory described in Section 4.4.1.2 contains the parameters of Quaternary-active faults in California. While it will be important to consider these faults in siting possible new injection operations, smaller local faults in the site vicinity will likely be of more direct relevance in assessing the potential for induced seismicity. These include faults having lengths on the order of 1 to 10 km (0.6–6.2 mi) capable of producing earthquakes between about M_w3.5 and 5, and even smaller ones that are potential sources of felt earthquakes. The fault inventory should also include inactive faults (i.e., activity predates the Quaternary) that are suitably oriented relative to the *in situ* stress field for shear failure. Both major and local faults that outcrop at the surface are shown on published geologic maps at scales as large as 1:24,000 (USGS 7.5 minute quadrangles). Unmapped faults on the kilometer scale, including buried structures, may be detectable in seismic and well data acquired during field exploration or characterization of specific injection sites. Faults on the 100-meter scale may be detectable depending on specific circumstances, but in general present a greater challenge. Finally, faults that are potential sources of induced earthquakes of concern and that escape detection during site

characterization may often be illuminated by low-magnitude microearthquakes recorded during the initial stages of injection.

Table 4.6-1. Summary of minimum magnitudes of complete detection, M_c, in onshore oil-producing basins. M_c values not adjusted to accountt for underestimation bias (see Appendix 4.A).

Basin	Mean M_c±1s	Min M_c	Max M_c
Los Angeles	1.5±0.2	1.1	2.0
Ventura	1.5±0.3	0.8	2.1
Santa Maria	1.6±0.3	1.1	2.1
Cuyama	1.4±0.2	0.9	1.7
San Joaquin	1.6±0.3	0.6	2.0
Salinas	1.0±0.3	0.3	1.3

4.6.4. In-situ Stresses and Fluid Pressures

Although there are a large number of stress measurements in California compared with other regions of the U.S., the point measurements in the World Stress Map database provide only a sparse sampling of the stress field. While overall trends in Figure 4.4-1 appear relatively uniform, significant variations are to be expected because stress states at the local scale are influenced by heterogeneously distributed fractures of varying orientation and by changes in lithology and rock material properties (e.g., Finkbeiner et al., 1997). Ideally, stress measurements at a given injection site are needed to assess the potential for induced seismicity. To achieve this, it may be possible to employ other measurement techniques in addition to borehole data and analysis of hydraulic fracture breakdown and shut-in pressures. For example, in a hydraulic fracturing experiment in the Monterey formation, Shemeta et al. (1994) studied the geometry of the hydrofracture using continuously recorded microseismic data, regional stress information, and well logs. They found that the microseismic and well data were consistent with both the regional tectonic stress field and fracture orientations observed in core samples and microscanner and televiewer logs. The results of this study suggest that observations of the natural fracture system can be used as indicators for the orientations of induced fractures and hence of the *in situ* stress. As with local microseismic monitoring, *in situ* stress measurements may be justified only at higher-risk sites. However, measurement or estimation of stress orientations prior to well stimulation is critical for selecting a development well pattern and the design of hydraulic fractures for effective hydrocarbon recovery. Such measurements can be used to inform induced seismic hazard assessment for well stimulation activities within a field, and also for any nearby wastewater disposal operations.

4.7. Findings

The dramatic increase in the rate of earthquake occurrence that has accompanied the boom in unconventional oil and gas recovery in the central and eastern U.S. since 2009

has highlighted the fact that injecting fluids into the subsurface for well stimulation by hydraulic fracturing—and, in particular, for disposal of recovered fluids and produced wastewater—can cause induced seismicity. Induced seismicity can occur when fluid injection results in increased pore pressure within a fault. This reduces the force holding the two sides of the fault together, allowing the fault to slip.

Hydraulic fracture treatments inject relatively small volumes injected over short time periods. As a result, the subsurface volume affected by pressure perturbations is normally within hundreds of meters from the injection well, which, current experience suggests, limits the size of induced seismic events caused by well stimulation. To date, the largest event generally considered to have been caused by hydraulic fracturing is the 2011 M_L3.8 earthquake in the Horn River Basin in British Columbia (BC Oil and Gas Commission, 2012).

Injection of large volumes of wastewater over long time periods increases pressures over much larger distances than those resulting from hydraulic fracturing, which increases the likelihood of inducing larger seismic events. Therefore, injection of wastewater presents a much larger potential seismic hazard than hydraulic fracturing. The largest earthquake suspected of being related to wastewater disposal is the 2011 M_w5.7 Prague, Oklahoma event (Keranen et al., 2013; Sumy et al., 2014), but the causal mechanism of this event is still the subject of active research. The possibility that this was a naturally occurring tectonic earthquake cannot yet be confidently ruled out. The largest earthquake for which there is clear evidence for a causative link to stimulation-related wastewater injection is the 2011 M_w5.3 event in the Raton Basin, Colorado (Rubinstein et al., 2014).

The potential impacts from ground shaking caused by induced seismicity are structural damage—and possibly injuries and loss of life—and nuisance resulting from seismic events that are felt in nearby communities. While the vast majority of fluid injection-induced earthquakes are too small to be perceptible at the ground surface, some are strongly felt and on rare occasions can be large enough to cause damage (e.g., Kerenan et al., 2013; Rubinstein et al., 2014). The magnitude threshold for local structural damage is generally considered to be about M_w5, depending on the depth of the earthquake, surface site conditions, and the fragility of nearby structures. To date, the maximum magnitudes of earthquakes induced by hydraulic fracturing worldwide have been substantially below this threshold, which suggests that the likelihood of seismic damage resulting from hydraulic fracturing in general is very low.

The likelihood of damaging events resulting from wastewater disposal is much higher than that from hydraulic fracturing. Four earthquakes greater than M4.5 related to wastewater disposal have occurred in the U.S. since 2011 (see Appendix 4.C), of which the 2011 Prague and Raton Basin events mentioned above caused localized structural damage. However, given that induced seismicity has been associated with only a small fraction of the tens of thousands of injection wells currently or formerly active in the U.S., viewed in a global context the overall likelihood of a damaging event being induced by wastewater injection is low in absolute terms.

The magnitude threshold for felt events can be as low as M1.5–2.0 for the shallow depths of seismicity that are typically associated with fluid injection. There are only five documented cases of seismicity related to hydraulic fracturing worldwide that included felt events, but numerous cases related to wastewater injection. Because, in general, the rate of earthquake occurrence increases by about a factor of ten for every decrease of one magnitude unit, the overall likelihood of nuisance from wastewater injection-induced earthquakes is relatively high.

4.8. Conclusions

Although induced seismicity occurs at several geothermal fields in California, there have been no published reports of felt seismicity linked to either hydraulic fracturing or wastewater disposal in the state, apart from one highly anomalous event reported by Kanamori and Hauksson (1992). However, in many areas of California, discriminating induced events in the M2-4 range from frequently occurring natural events is difficult, and the systematic studies necessary have begun only recently.

The lack of reported felt seismicity related to hydraulic fracturing is consistent with injection into predominantly vertical wells at relatively shallow depths in California and the small injection volumes currently employed. Therefore, based on experience elsewhere, hydraulic fracturing as currently carried out in California is not considered to pose a high seismic risk.

The total volume of wastewater injected in California is much larger than the volume used for well stimulation, but current volumes are relatively small compared to the regions in the U.S. that have recently experienced large increases in induced seismic activity related to wastewater disposal. Although this might imply a lower current potential for induced seismicity than in the mid-continent, the relationship between seismicity and wastewater injection in California has not been fully evaluated. Therefore, the potential level of seismic hazard posed by wastewater disposal is at present uncertain. A comprehensive, in-depth study of spatial and temporal correlations, if any, between wastewater injection and seismicity will be required to provide a firm basis for assessment of seismic hazard related to induced seismicity.

As evidenced by the upswing in induced seismicity in the central and eastern U.S. since 2010, an increase in hydraulic fracturing activity and expanded production in California could increase the seismic hazard from wastewater disposal and perhaps also from hydraulic fracturing, particularly if they involve higher per-well injected volumes approaching those employed elsewhere in the U.S. and a shift to deeper stimulation. However, based on the data presented in Volume I of this study, such shifts in well stimulation in California are not expected in the near or mid term.

The closest wastewater disposal wells to the SAF are located in oilfields just over 10 km (6.2 mi) away in the southern San Joaquin Valley. It is unlikely that current wastewater injection in these wells would induce earthquakes on the fault. If future high-volume

injection took place in or close to these existing oilfields, it is plausible that the likelihood of triggering earthquakes on the SAF could increase.

Even if the overall potential for induced seismicity in California proves to be low, some level of incremental seismic hazard and risk assessment to inform permitting and regulation of stimulation-related injection projects is justified. Initial low-level assessment during site screening could be used to place each site into one of a few risk categories, based on planned injection rate, cumulative volume and depth, distance from active or potentially active faults, estimated pressure changes on those faults, background seismicity, and proximity to population centers and critical facilities. An appropriate level of probabilistic seismic hazard and risk assessment would then be carried out for sites in higher risk categories, and the permit would specify bounds on injection parameters to achieve an acceptable level of risk. For these sites, monitoring requirements and operating procedures to manage and, if necessary, mitigate induced seismicity during injections would also be specified.

Injection projects that could possibly cause significant pressure changes on the most active major faults like the SAF should be subject to the most stringent risk assessment and regulatory requirements.

The mechanics of fluid-induced seismicity are fairly well understood, and, as such, it is theoretically possible to carry out full hazard assessments at higher-risk sites. However, much more detailed information on injection than is currently available in publicly available databases will be required, first to gain an understanding of the potential for induced seismicity in California oil-producing basins, and then to carry out hazard and risk assessments. Site-specific investigations will also require definition of local faults, the state of stress on those faults, characterization of rock, fault, and hydrological properties, measurement or modeling of the subsurface pressure perturbation based on injection rates, and characterization of the seismicity at the site and in the surrounding area.

Two aspects of the current DOGGR (2014a) database limit its usefulness in identifying past induced seismicity. First, injected volume rates and wellhead pressures are reported only as (presumed) monthly averages, whereas peak volumes, rates and pressures, and significant short-term variations are of relevance in detecting effects on seismicity. Secondly, depth information is not available for the majority of wastewater injection wells. Filling these gaps in the existing database would facilitate a much more comprehensive analysis of the correlations of injection with seismicity. More complete reporting in the future would enable hazard and risk assessment and mitigation of induced seismicity for new stimulation-related injection operations.

Adequate characterization of local seismicity requires recording of local microearthquakes as small as about M1 or less. Existing regional and local networks provide this detection capability in some areas of California, but the threshold for complete detection in some oil-producing basins is M2 or higher, which presents an obstacle to discriminating

potential past induced seismicity in these areas. Moving forward, local microearthquake networks should ideally be installed to monitor seismicity at higher-risk sites located in areas currently having detection thresholds higher than about M1.

The current compilation of stress data for California provides only a sparse sampling of the regional *in situ* field in most areas within oil-producing basins. Therefore, detailed analysis of the potential for induced seismicity and seismic hazard assessment at higher-risk sites would ideally utilize site-specific stress measurements obtained from borehole data and other techniques. Similarly, detecting faults that are potential sources of felt or perhaps damaging induced earthquakes will require site-specific characterization to augment the existing active fault database and geologic maps. Advanced detection of faults on the 100 m to 1 km (328 to 3280 ft) scale that may be sources of small felt earthquakes presents a particular challenge, but these may be revealed by low-magnitude microseismicity during the initial stage of injection.

Inevitably, many of the parameters needed for induced seismicity hazard calculations will be poorly constrained. However, seismic hazard assessment in general is invariably subject to considerable uncertainty, and an important and mature part of the PSHA procedure is to properly characterize the uncertainties in the input parameters, and then propagate them through the calculation to provide rigorous uncertainty bounds on the final hazard estimates.

Induced seismicity that could potentially accompany an increase in well stimulation activity in California could likely be managed and mitigated by adopting a protocol similar to the one developed by the U.S. DOE for enhanced geothermal systems. In addition to hazard and risk assessment, one of the core recommendations in the U.S. DOE protocol is provision of a set of procedures to modify an injection operation in response observed changes in seismicity. These entail staged reduction in injection flow rate and pressure up to and including well shutdown. The procedures should be based on quantitative forecasts of the probability of inducing earthquakes of concern derived from observations of evolving seismicity and changes to the state of the reservoir, rather than the essentially ad hoc criteria that have been employed to date.

4.9. References

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Chapter Five

Potential Impacts of Well Stimulation on Wildlife and Vegetation

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5.1. Abstract

In this chapter, we examine the impact of well stimulation on California's wildlife and vegetation. Potential impacts to wildlife and vegetation from oil and gas operations using well stimulation considered in this chapter are: (1) habitat loss and fragmentation, (2) introduction of invasive species, (3) releases of harmful fluids to the environment, (4) diversion of water from waterways, (5) noise and light pollution, (6) vehicle collisions, and (7) ingestion of litter by wildlife.

In this chapter we focus on habitat loss and fragmentation, because it was the only impact for which we had sufficient data to quantify impacts, and because our analysis indicates that habitat loss and fragmentation caused by production enabled by hydraulic fracturing is large enough to be of concern for habitat conservation in Kern and Ventura counties.

The degree to which hydrocarbon production and natural habitat come into contact depends on two major factors: (i) the density of oil and gas production infrastructure, and (ii) other human land uses in the area. Areas dominated by near-continuous well pads are largely inhospitable to native wildlife and vegetation. In other places, oil and gas production, including operations that use well stimulation, is interspersed with agricultural and urban development that has already displaced native habitat. In contrast, large portions of some oil fields have little other development and a relatively low density of oil wells. Native species inhabit the areas in and around these oil fields.

In areas where there is natural habitat, new oil and gas development impacts native species via a variety of mechanisms, the most well-understood of which is habitat loss and fragmentation. New wells bring new well pads, new roads, more vehicle traffic, and

other human activities that alter open land in ways that can make it uninhabitable to most wildlife and vegetation. In California, most hydraulic-fracturing-enabled-development takes place in and around areas that were already producing oil and gas without the application of well stimulation. Well stimulation, in particular hydraulic fracturing, has enabled an increased density of oilfield development and alight increases in the footprint of developed areas. Our analysis of habitat types, vegetation cover, well density and well stimulation activity in California indicates that impacts of well stimulation to wildlife and vegetation are most pronounced in the southwest portion of the San Joaquin Basin and the transverse ranges in the Ventura basin.

Aside from habitat loss and fragmentation, we are unable to quantify the impacts of well stimulation on wildlife and vegetation in California using available data, and we restrict our discussion of them to general description and literature review.

We also discuss the relevant rules and regulations governing impacts to wildlife and vegetation from oil and gas activities. Although regulations exist to evaluate and mitigate site- or project-specific impacts when new oil and gas development is proposed, the agencies of jurisdiction have not routinely evaluated the incremental impacts of individual oil and gas development projects within the larger context of habitat loss and fragmentation at the regional level. We also discuss the most commonly implemented best practices and mitigation measures. We conclude with a discussion of important data gaps, particularly a lack of information to more precisely quantify impacts of well stimulation on population growth rates of species, a poor understanding of the degree to which abandoned oil and gas leases can be restored, and a lack of studies evaluating the efficacy of best practices and mitigation measures.

5.2. Introduction

There are a number of potential ways that well stimulation can affect wildlife and vegetation. In this chapter we discuss potential impacts due to: (1) loss and fragmentation of habitat, (2) introduction of invasive species, (3) contamination of the aquatic environment, (4) diversion of water from waterways, (5) noise and light pollution, (6) vehicle traffic, and (7) ingestion of litter. Most of these impacts are not directly caused by the process of well stimulation, but are common to any form of oil or gas production.

Many of the impacts to wildlife and vegetation require an intermediary such as water use or contamination, light and noise pollution, or increases in traffic that are discussed in other chapters in this volume: water use or contamination in Chapter 2, and noise, light and traffic in Chapter 6. This chapter examines these topics with an eye to their potential effect on wildlife and vegetation. We also explore the following potential impacts that are not discussed elsewhere in Volume II: habitat loss, introduction of invasive species, and ingestion of litter by wildlife. We focus most of our quantitative analysis on the impact of well-stimulation-enabled hydrocarbon production on habitat loss for three reasons. First, of the seven potential impacts listed in Table 5.2.1, habitat loss was the only impact

with sufficient data available to conduct a statewide quantitative assessment. Second, habitat loss is a well-documented impact of oil and gas development in the terrestrial environment (Weller et al., 2002; Northrup, 2013). Last, habitat loss is generally regarded as the leading cause of biodiversity loss on the planet, followed by invasive species, pollution, and commercial exploitation (Moyle and Leidy, 1992; Wilcove et al., 1998). Closely related to habitat loss is fragmentation. The general principle behind habitat fragmentation is that the configuration as well as the quantity of habitat remaining affects the survival of species. Habitat fragmentation is not discussed in depth here, but is discussed in the San Joaquin Case Study in Volume III.

We note whether impacts are direct or indirect throughout the chapter. Direct impacts are uniquely associated with well stimulation and do not occur when oil and gas are produced without the aid of well stimulation. Examples of direct impacts of well stimulation include a spill of stimulation chemicals, or noise generated by equipment used in hydraulic fracturing. Indirect impacts stem from other aspects of the oil and gas production process apart from well stimulation. Examples of indirect impacts include the construction of a well pad and other infrastructure necessary for oil and gas production (resulting in habitat loss), and disposal of produced water (which can contaminate habitat). If these impacts are incurred by a well that is only economical to produce with the enabling technology of hydraulic fracturing, then they are indirect impacts. In other words, a proportion (but not all) of the indirect impacts to wildlife and vegetation caused by oil and gas production are enabled by hydraulic fracturing, since certain low-permeability reservoirs are not economical to produce without the technology. Matrix acdizing and hydraulic fracturing are not important drivers of increased production in California.

Habitat loss and fragmentation, introduction of invasive species, and litter are indirect impacts of hydraulic fracturing: they are not caused uniquely by hydraulic fracturing, but by expanded development and production allowed by hydraulic fracturing. Contamination of the aquatic environment, diversion of water from waterways, noise and light pollution, and vehicle traffic can be direct or indirect impacts, depending on context – for example, a spill of stimulation chemicals would be directly attributable to well stimulation, whereas a spill of produced water would be an indirect impact. The distinction between direct and indirect impacts is important because it has policy implications. Banning hydraulic fracturing would eliminate direct impacts. It would reduce indirect impacts, but not eliminate them, since indirect impacts are also caused by other forms of oil and gas production. For a more detailed discussion of direct and indirect impacts, please see the Summary Report.

Volume I of the report found that hydraulic fracturing is an important driver of expanded production in the state, whereas acid stimulations are not (Volume I, Chapter 1, Finding 5). Consequently, hydraulic fracturing is the only well-stimulation technology driving expanded hydrocarbon production in the state and thereby causing indirect impacts such as habitat loss and fragmentation. We discuss well stimulation as a whole, including acid stimulations, when addressing direct impacts, such as potential releases of stimulation fluids to the environment.

5.2.1. Overview of Chapter Contents

This chapter covers five major topics. In Section 5.2, the Introduction, we describe the ecology of Kern and Ventura counties, the two regions where we found major impacts from hydraulic fracturing-enabled production. We also describe land use patterns within the administrative boundaries of oil fields. In Section 5.3, "Assessment of Well Stimulation Impacts to Wildlife and Vegetation," we describe how well stimulation can impact wildlife and vegetation in California. Each potential impact is defined and relevant literature is reviewed. Whenever possible we discuss studies conducted in California, although most of the available work was not peer reviewed, and the majority focus on one region in the San Joaquin Valley. Because habitat loss and fragmentation is likely to have the greatest impact on wildlife and vegetation, we explore this topic in greater depth by quantifying habitat loss and fragmentation attributable to well-stimulation-enabled hydrocarbon production. We also summarize the potential future impacts to wildlife and vegetation. In Section 5.4, we describe how oil and gas production activities are regulated with respect to their impacts on wildlife and vegetation. In Section 5.5, we discuss measures to mitigate oil field impacts on terrestrial species and their habitats. In Section 5.6 we assess major data gaps and ways to remedy the gaps. In Sections 5.7 and 5.8, we summarize the major findings and conclusions of the chapter.

5.2.2. Regional Focus: Kern and Ventura Counties

In our analysis, we focused on the areas in the state where substantial amounts of well stimulation occurred in the context of undeveloped areas of natural habitat. We evaluated the ecological impacts of hydraulic-fracturing-enabled development with respect to the impact to loss of natural habitat, the rarity of that habitat statewide, and occurences of endangered species and designated critical habitat in the vicinity. Two regions emerged as locations where hydraulic-fracturing-enabled development was heavily impacting natural habitat. The first was southwest Kern County in the vicinity of Elk Hills, North and South Belridge, Buena Vista, and Lost Hills Fields. The second key region was along the southern perimeter of Los Padres National Forest in Ventura County, in the Ojai and Sespe Fields, within the Santa Barbara-Ventura Basin (referred to for brevity as the Ventura Basin). Matrix acidizing is much rarer and tends to be concentrated in southwestern Kern county. As a result, we focus our discussion primarily on Kern County, and secondarily on Ventura County, followed by other counties in the state.

5.2.2.1. Kern County: Ecology, Oil and Gas Development, and Well Stimulation

Kern County lies in the southern portion of the San Joaquin Valley, which was a region once dominated by lakes, wetlands, riparian corridors, valley saltbush scrub, and native grasslands. Most of the natural habitat has been converted to agricultural or urban use since the mid-19th century (Figure 5.2-1). Owing primarily to loss of habitat, there are

approximately 143 federally-listed species, candidates and species of concern[1] with distributions wholly or partially in the San Joaquin Valley (Williams et al., 1998). For comparison, there were 568 state and federally listed and candidate species in California as of 2015 (Biogeographic Data Branch DFW, 2015a; b). The majority (76%) of California's remaining valley saltbush scrub habitat and its associated endangered species persists in southwestern Kern County. This area also has major petroleum resources. As a result, forty-two percent of California's remaining valley saltbush scrub habitat is within the boundaries of a Kern County oil field (Appendix 5.D, Table 5.D-1). The relationship is not entirely coincidental. The giant oil fields of the southwestern San Joaquin Valley such as Midway-Sunset, North and South Belridge, Elk Hills, Buena Vista and Lost Hills were discovered between 1894 and 1912 and were controlled by oil development interests before agriculture dominated the region. Within large portions of those oil fields, development is sparse enough that native habitat, principally valley saltbush scrub and non-native grassland, persists. Very little of the original aquatic and wetland habitats of the San Joaquin Valley remain, with more than 90% of open water, wetlands, and riparian habitat converted to farmland and cities (Kelly et al., 2005).

1. "Federally-listed" refers to species listed as endangered or threatened under the Endangered Species Act. "Candidate species" are organisms for which the U.S. Fish and Wildlife Service has sufficient information on their biological status and threats to propose them as endangered or threatened under the Endangered Species Act, but for which development of a proposed listing regulation is precluded by other higher priority listing activities. "Species of concern" are deemed to be potentially in decline, but are not presently candidates for listing.

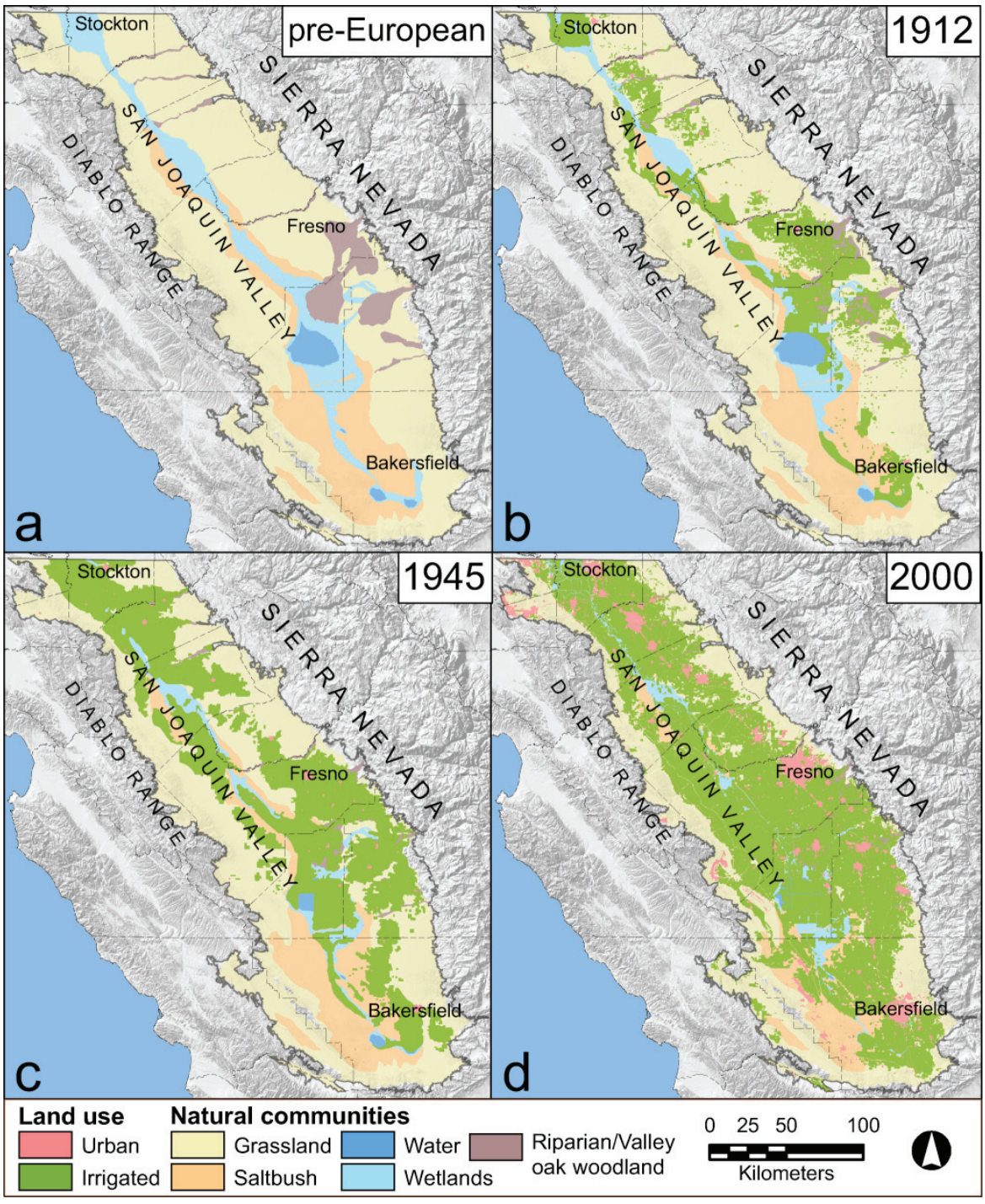


Figure 5.2.1. Maps of the San Joaquin Valley from pre-European settlement to the year 2000. The majority of natural habitat in the region has been converted to human use, principally agriculture, over the past century. The bulk of remaining valley saltbush scrub habitat is in the southwestern San Joaquin, where a combination of hillier terrain and ownership by oil developers prevented conversion to agriculture. Reprinted with permission from Kelly et al. (2005).

Kern County has the highest density of hydraulic fracturing and matrix acidizing in the state. More than 85% of hydraulic fracturing in the state occurs in six fields in southwestern Kern County: North and South Belridge, Elk Hills, Lost Hills, Buena Vista, and Midway-Sunset (Volume I Section 3.2.3.2, "Location)." More than 95% of matrix acidizing occurs in three fields in the same region: Elk Hills, Buena Vista, and Railroad Gap (Summary Report).

5.2.2.2. Ventura County: Ecology, Oil and Gas Development, and Well Stimulation

Ventura County is dominated by chaparral and Venturan coastal sage scrub with some dispersed riparian and annual grassland areas. The southern portion of the county has largely been converted to urban and agricultural use, while the northern half overlaps with Los Padres National Forest. Because much of southern California has been so heavily altered by human use, the national forest serves as an important refuge for species extirpated elsewhere in the region. It provides habitat for 468 permanent or transitory species of fish and wildlife, over 100 of which are listed as federally- or state-endangered, threatened, or sensitive[2] (CDFW, 2014a; 2014b; USFWS, 2014b). Listed species in the region include the vernal pool fairy shrimp, the Southern willow flycatcher, the California red legged frog, the California condor, southern steelhead, Least Bell's Vireo, and the Santa Ana sucker. Typical habitat types are buck brush chaparral, chamise chaparral, and Venturan coastal sage scrub (UCSB Biogeography Lab, 1998).

While the total number of wells and hydraulic fracturing is much lower in Ventura than Kern County, a high proportion of the activity was enabled by hydraulic fracturing in eleven oil fields in the Ventura Basin (Volume I, Appendix N). Two fields, the Ojai and the Sespe, fall at least partially within the Los Padres National Forest and abut the Sespe Wilderness, home to the Sespe Condor Sanctuary. The Sespe Oil Field is also adjacent to the Hopper Mountain National Wildlife Refuge.

5.2.2.3. The Ecology of Kern and Ventura County Oil Fields

There is a common misperception that there is little or no natural habitat in areas developed for oil and gas production. In fact, oil and gas production, including operations that use well stimulation, is often interspersed with natural habitat (Fiehler and Cypher, 2011; Spiegel, 1996). As a result, native biota, including listed species, can be found in and around some areas developed for oil and gas, notably in Kern and Ventura Counties (USFWS, 2005; Fiehler and Cypher, 2011). However, other oil fields are dominated by human land uses to the exclusion of natural habitat.

2. Sensitive plants include those plants listed as endangered, threatened or rare (Section 670.2, Title 14, California Code of Regulations; Section 1900, Fish and Game Code; ESA Section 17.11, Title 50, Code of Federal Regulations) or those meeting the definitions of rare or endangered provided in Section 15380 of the CEQA Guidelines.

The degree to which natural habitat persists on oil fields depends primarily on two factors: (i) the density of oil and gas production infrastructure, and (ii) other human land uses in the area. Areas dominated by near-continuous well pads, such as large expanses of the North and South Belridge, Lost Hills, and Ventura Oil Fields, are largely inhospitable to native wildlife and vegetation (Fiehler and Cypher, 2011 and **Figure 5.2.2**a). In other places, oil and gas production is interspersed with agriculture and urban development that by themselves displace the native habitat. Oil fields such as Rose and North Shafter are dominated by agriculture and urban development with scattered oil wells; there is virtually no intact natural habitat remaining in those regions, so oil development in those areas has little impact on wild animals and vegetation (**Figure 5.2.2**b).

In contrast, large portions of oil fields such as Elk Hills, Lost Hills and Buena Vista in Kern County and Ventura, Ojai and Sespe in Ventura are otherwise unimpacted by human development and have a relatively low density of oil wells (**Figure 5.2.2**c). Native species can survive on and around these oil fields. For example, outside of the Carrizo Plain Natural Area in San Luis Obispo County, the largest extant populations of the federally endangered/state threatened San Joaquin kit foxes are in the Elk Hills and Buena Vista oil fields in Kern County (USFWS, 2005). **Figure 5.2.3** and **Figure 5.2.4** depict areas of varying well density and land use in the southern San Joaquin Valley and Ventura County. Areas denoted as having medium or low well density that are not developed for human use are areas where habitat interacts with oil and gas production.

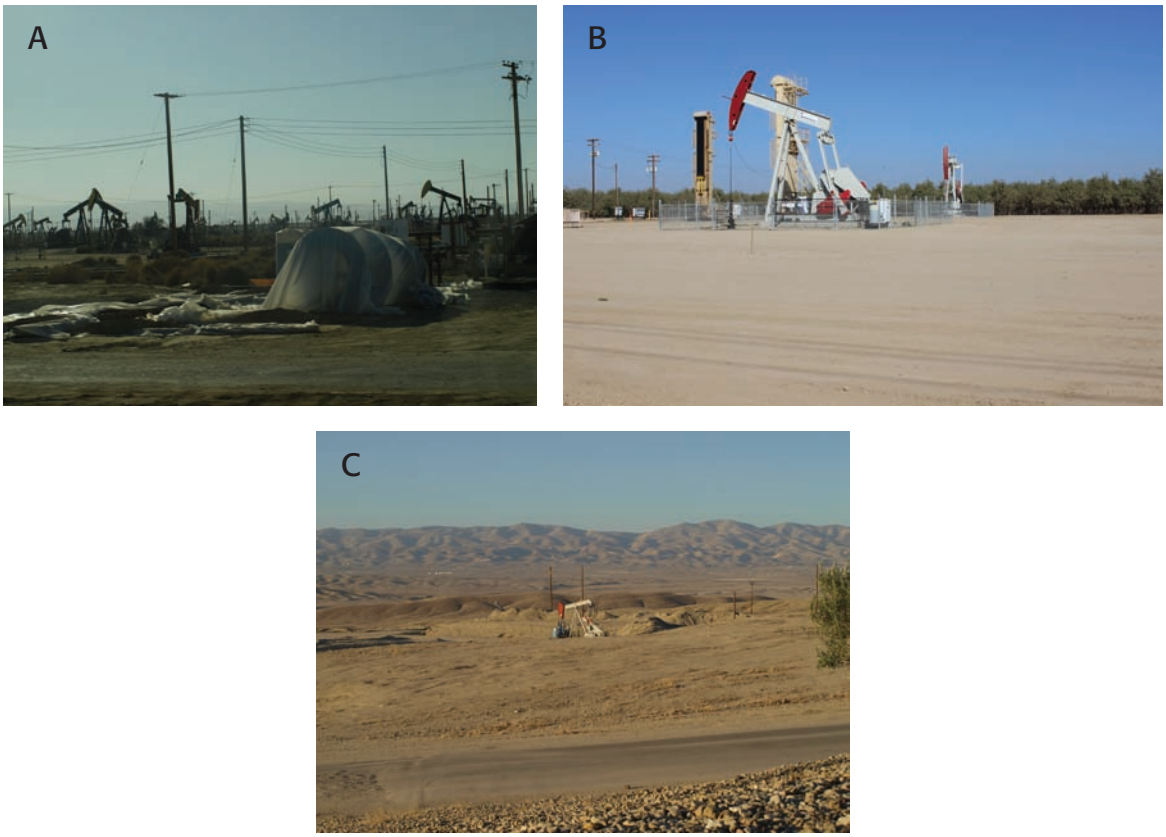


Figure 5.2.2. (a) An area of high well density at Lost Hills field is largely inhospitable to the native biota. (b) Pump jacks in the North Shafter field are surrounding by a fallow field and an orchard; there is little or no native habitat. (c) The Elk Hills Oil Field in Kern County has areas of low well density surrounded by large areas of intact valley saltbush scrub vegetation, habitat for a number of threatened and endangered native species. While well stimulation takes place in all three fields, activities in areas surrounded by native habitat are more likely to have ecological impacts. Photo credits: (a) C. Varadharajan, (b) L. Feinstein, (c) C. Varadharajan, 2014.

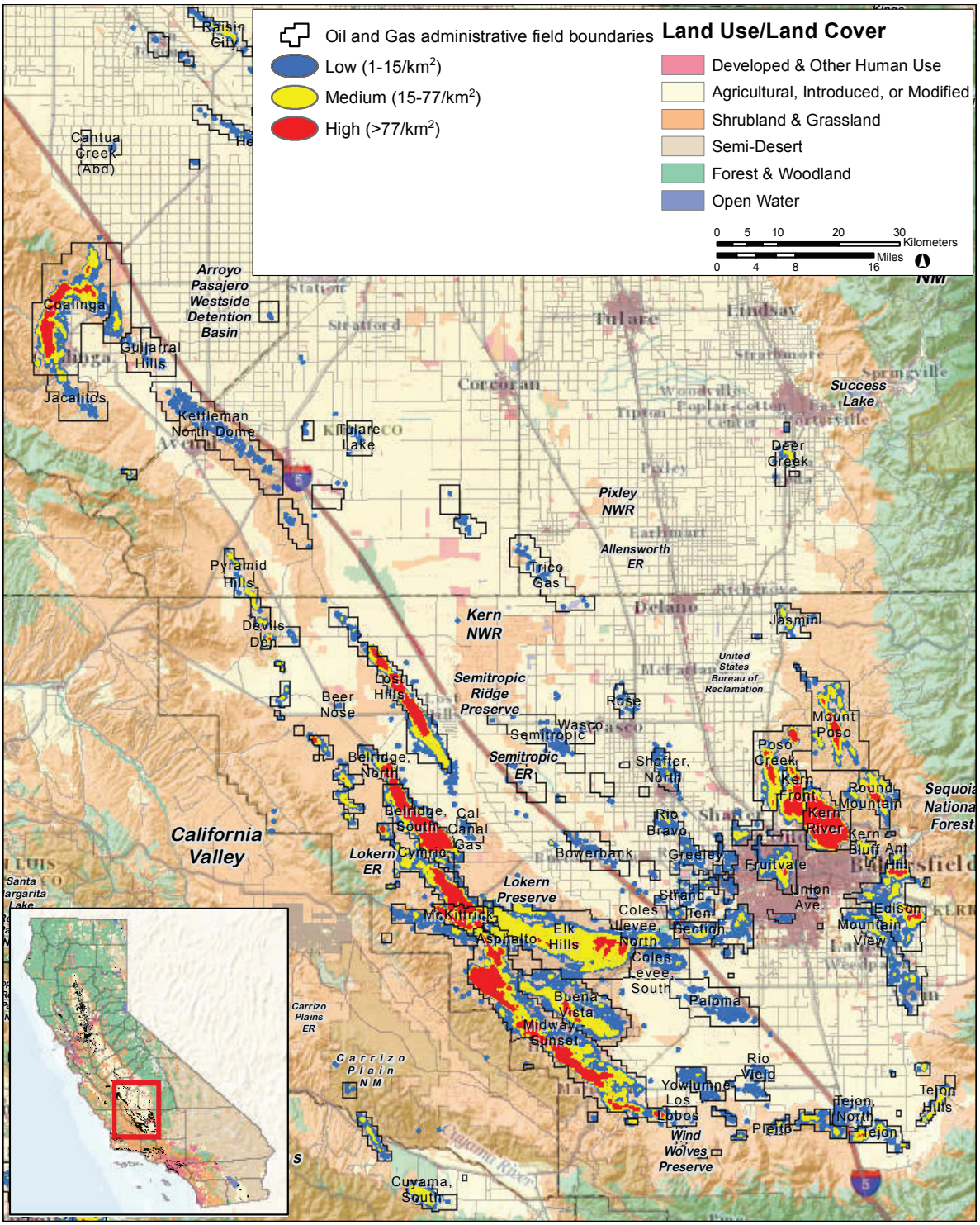

Oil and Gas administrative field boundaries
Low (1-15/km²)
Medium (15-77/km²)
High (>77/km²)
Land Use/Land Cover
Developed & Other Human Use
Agricultural, Introduced, or Modified
Shrubland & Grassland
Semi-Desert
Forest & Woodland
Open Water
0 5 10 20 30 Kilometers
0 4 8 16 Miles
Raisin City
Cantua Creek (Abd)
Arroyo Pasajero Westside Detention Basin
Coalinga
Guijarral Hills
Jacalitos
Kettleman North Dome
Tulare Lake
Corcoran
Pixley NWR
Allensworth ER
Trico Gas
Pyramid Hills
Devils Den
Kern NWR
Semitropic Ridge Preserve
Beer Nose
Lost Hills
Wasco Semitropic
Semitropic ER
Rose
United States Bureau of Reclamation
Jasmin
Mount Poso
Poso Creek
Kern Front
Kern River
Round Mountain
Sequoia National Forest
Shafter, North
Rio Bravo
Greeley
Fruitvale
Bowerbank
Kern Bluff
Ant Hill
Belridge, North
Belridge, South
Cal Canal Gas
Cymric
Lokern ER
Lokern Preserve
McKittrick
Asphalto
Elk Hills
Coles Levee North
Coles Levee South
Strand Ten Section
Union Ave.
Edison
Mountain View
Paloma
Buena Vista
Midway Sunset
California Valley
Carrizo Plains ER
Carrizo Plain NM
Rio Viejo
Yowlumne
Los Lobos
Wind Wolves Preserve
Tejon North
Tejon
Tejon Hills
Cuyama, South
Santa Margarita Lake

Figure 5.2.3. Well density in the southern San Joaquin (and Cuyama) basins. Opaque blue, yellow and red indicate the density of wells, both stimulated and unstimulated; all wells that had recorded activity recorded activity from January 1977 through September 2014 are shown. Background shading indicates land use and cover categories. Larger versions of these maps, and maps of other basins, can be found in Appendix 5.B. Data from California Division of Oil, Gas and Geothermal Resources (DOGGR), 2014a; 2014b; 2014c; UCSB Biogeography Lab, 1998; California DOC, 2012.

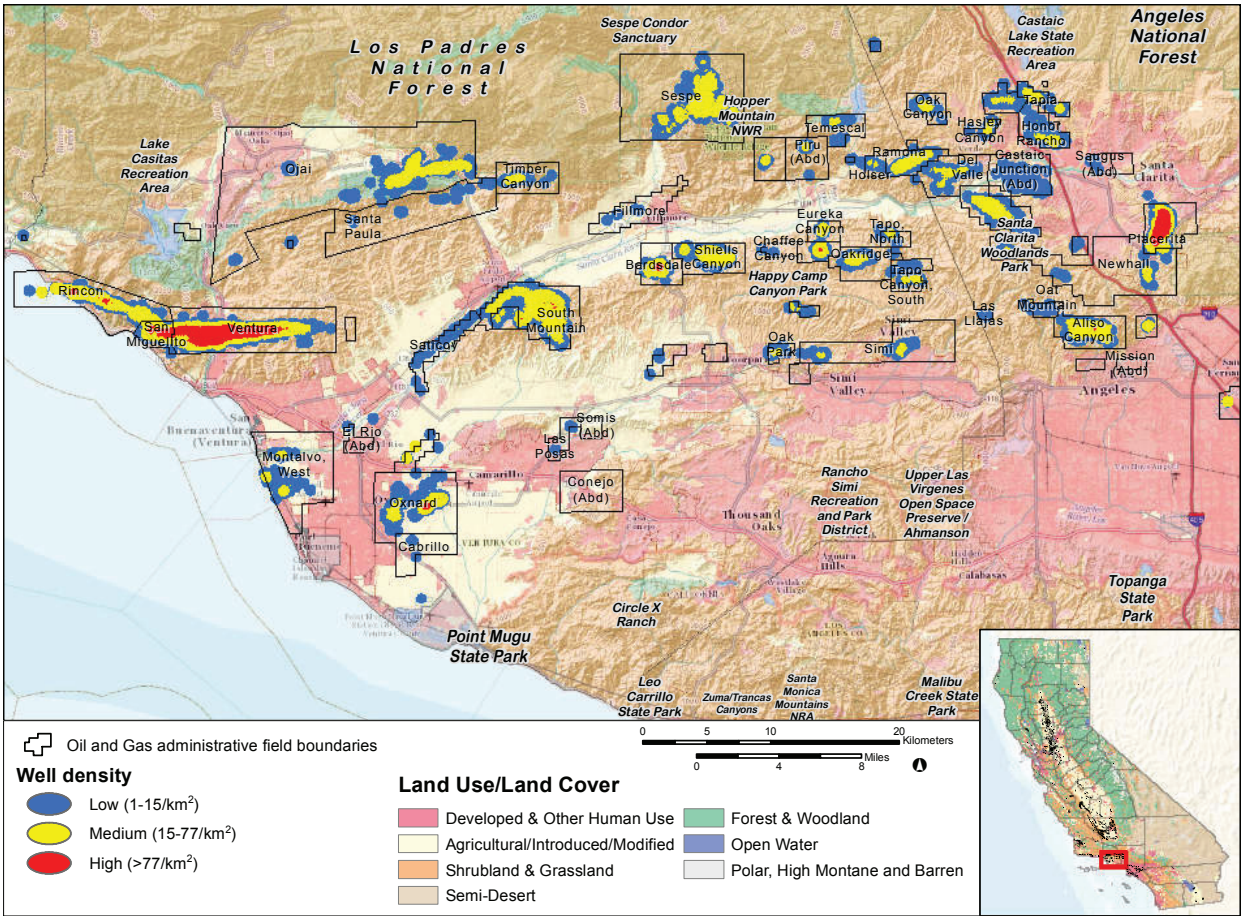


Figure 5.2.4. Well density in Ventura Basin. Opaque blue, yellow and red indicate the density of wells, both stimulated and unstimulated; all wells that had recorded activity recorded activity from January 1977 through September 2014 are shown. Background shading indicates land use and cover categories. Larger versions of these maps, and maps of other basins, can be found in Appendix 5.B. Data from DOGGR, 2014a; 2014b; 2014c; UCSB Biogeography Lab, 1998; California DOC, 2012.

5.3. Assessment of Well Stimulation Impacts to Wildlife and Vegetation

In this section we describe the following ways that well stimulation can impact wildlife and vegetation: habitat loss and fragmentation, facilitating invasive species, discharging potentially harmful fluids, use of water, noise and light pollution, traffic, and litter. Because we expect habitat loss and fragmentation to have the greatest effect on wildlife and vegetation, and adequate data was available, we conduct an original quantitative analysis on the topic, in which we identify the areas where well stimulation has had the greatest impact, how much of various habitat types were affected, and describe in detail the special-status species that occur in the vicinity.

5.3.1. Land Disturbance Causes Habitat Loss and Fragmentation

5.3.1.1. Overview and Literature Review of Habitat Loss and Fragmentation

Oil and gas production contribute to habitat loss and fragmentation through the construction of well pads and support infrastructure and related land disturbance, not directly by hydraulic fracturing itself (Jones and Pejchar, 2013). Expanding production of unconventional resources in new areas, often in areas of open habitat relatively unaffected by people, is resulting in habitat loss and fragmentation in areas such as Canada (Council of Canadian Academies, 2014), Wyoming (Thomson et al., 2005), Colorado (Jones and Pejchar, 2013), and Pennsylvania (Johnson et al., 2010). Unlike California, in regions where the only hydrocarbons produced are from source rock, all oil and gas production is indirectly attributable to hydraulic fracturing. For example, Pennsylvania's Marcellus Shale is only producible with hydraulic fracturing, and it underlies valuable forest and freshwater habitat. In regions outside of California, there are a number of locations where hydraulic fracturing enables production in areas never before developed for oil and gas. When these areas happen to underlie areas of relatively pristine habitat, the oil and gas production enabled by hydraulic fracturing causes habitat loss and fragmentation (Slonecker et al., 2013; Roig-Silva et al., 2013; Johnson et al., 2010).

In California, it is difficult to isolate the impact of hydraulic fracturing on habitat from the impacts of oil and gas production in general. This is because most hydraulic fracturing is occurring on lands that would be used for oil and gas production regardless of hydraulic fracturing. This is because hydraulic fracturing is necessary for production from certain types of low-permeability reservoirs. In many places in California, these low-permeability reservoirs are stacked vertically with reservoirs that do not require hydraulic fracturing. As a result, at the land's surface, wells that are hydraulically fractured are interspersed with wells that are not, because they are tapping different vertical layers of rock with different geologic properties.

Roughly half of the wells installed in California in the past decade were hydraulically fractured, and about one in fifteen were acidized; 85% of this activity is the North Belridge, South Belridge, Elk Hills and Lost Hills fields. These fields were discovered more

than a century ago (Volume I, Executive Summary; California Division of Oil, Gas and Geothermal Resources (DOGGR), 1998). We found that hydraulic-fracturing-enabled oil production is occurring within regions with a wide spectrum of existing habitat, including: (1) relatively intact habitat, (2) areas already disturbed by other oil and gas production, and (3) locations dominated by human uses such as agriculture or urban development. We attempted to isolate the impact of hydraulic-fracturing-enabled production on natural habitat by analyzing hydraulic-fracturing-enabled production in the context of the underlying land use.

Over the last century, habitat loss has been the largest documented impact to wildlife and vegetation stemming from oil and gas production activities in California. The extent of the impact was dependent upon the amount and the location of disturbances. Fiehler and Cypher (2011) found that valley saltbush scrub specialists such as San Joaquin antelope squirrels, short-nosed kangaroo rats and San Joaquin kit foxes disappeared from high density oil development, but persisted in areas with less than 70% disturbance. Construction activities that destroyed active den or burrow sites had significant impacts on San Joaquin kit fox populations (O'Farrell and Kato, 1987; Kato and O'Farrell, 1986; O'Farrell et al., 1986). On the other hand, nightly movements (Zoellick et al., 1987), den use patterns (Koopman et al., 1998), and reproductive and survival parameters of the San Joaquin kit fox did not differ between an undeveloped area and an intensely developed area of an oil field (Spiegel and Tom, 1996; Spiegel and Disney, 1996; Cypher et al., 2000).

Smaller species such as blunt-nosed leopard lizards and giant kangaroo rats were minimally impacted by oil and gas production because most of the activities were outside the core habitat areas for both species (O'Farrell and Kato, 1987). In areas where high-quality habitat and activities overlapped, the intensity of development and amount of habitat disturbed determined the carrying capacity[3] (Kato and O'Farrell, 1986). It has been documented that abandoned oil and gas fields undergoing revegetation can be recolonized by blunt-nose leopard lizards as long as densities of shrubs and ground cover do not become excessive (O'Farrell and Kato, 1980).

The studies we surveyed for impacts of oil and gas production to habitat loss and fragmentation within California were all conducted at the Elk Hills oil field, therefore it is difficult to assess the generality of the results to the rest of the state. There also were some limitations to the study designs, principally that the non-developed areas used for comparisons were not equivalent in habitat quality when compared to the developed areas, even prior to any activity.

3. The carrying capacity is the number of individuals of a species that an area can support.

5.3.1.2. Quantitative Analysis Of Hydraulic Fracturing-Enabled Production On Habitat Loss

Our analysis addressed three major questions:

1. How has hydraulic-fracturing-enabled oil production altered well density in California?

2. How are the areas with increased well density distributed across counties, land uses, and habitat types in California?

3. What special-status species occurred in the vicinity of oil fields highly impacted by well stimulation?

5.3.1.2.1. Methods

Here we briefly summarize our methods for the quantitative analysis of the impact of hydraulic fracturing on habitat loss; more information is given in Appendix 5-C, "Detailed Methods for Quantitative Analysis of Hydraulic Fracturing-Enabled Production On Habitat Loss."

For our analysis, we looked at well density as a proxy for habitat loss. As well density increases, the amount of intact habitat tends to decrease; see Figure 5.3.1. for an illustration of how plant cover is affected by increasing well density. We examined 506 plots at least 10 hectares (ha) in size for well density and bare (unvegetated) ground and found that well density predicted 95% of the variation in presence of bare ground. We concluded that well density is an accurate indicator of habitat loss.[4] For this analysis we did not look at how well density correlated with habitat fragmentation; we will look more closely at the issue of fragmentation in the San Joaquin case study in Volume III of this report.

In order to assess the impact of hydraulic-fracturing-enabled oil production on habitat, we set out to quantify the density of hydraulically fractured wells in the state. This was challenging given that reporting of hydraulic fracturing was not required until 2013, so records of the activity are likely incomplete. We used a compilation of well records, voluntary reporting to FracFocus, and recent mandatory reporting to estimate the proportion of hydraulically fractured wells tapping each pool (also called reservoirs). We then generated two alternate scenarios: actual well density, and a "without hydraulic fracturing" well density. Actual well density is the true density of wells in California

4. We performed a linear regression of proportion of bare ground as predicted by well density for 506 plots at least 10 hectares in size. The relationship was highly significant; $F(1,504) = 9107$, $p=<2.48x10^{-7}$, adjusted $r^2 = 0.95$. See Appendix 5.C for further details.

as of September 2013. Background well density represents a hypothetical scenario representing the well density of California as of September 2014 if every well that had been hydraulically fractured vanished. The difference between the two is the marginal impact of hydraulic fracturing-enabled production on well density and, by proxy, habitat loss and fragmentation.

An important point to understand about this analysis is that hydraulic fracturing compared to background well density does not represent a change over time. That is, well density was *not* at the background level at some point in time, then hydraulic fracturing increased the density from that time forward. Hydraulically fractured and unstimulated wells continue to be drilled and produced simultaneously. The main reason why wells that are hydraulically fractured are geographically interspersed with other wells in California is because low-permeability reservoirs that require hydraulic fracturing are often stacked above and below reservoirs that do not require hydraulic fracturing. For example, in the South Belridge field, the Tulare pool is above the Diatomite pool. 91% of well records in the Diatomite report hydraulic fracturing, as compared to only 1% in the Tulare. This creates a patchwork of wells at the surface that are and are not hydraulically fractured. Even if all hydraulically fractured wells disappeared from South Belridge, the well density in much of the field would still be high, and there would be little usable habitat for native organisms.

We split well density into four categories comparable to those used in Fiehler and Cypher (2011): Control – less than one well/km^2; Low – 1-15 wells/km^2; Medium - 15-77 wells/km^2; High - more than 77 wells/km^2. We chose to use the same categories because Fiehler and Cypher (2011) conducted the only previous work we could find systematically associating land disturbance from oil and gas activities with the decline of natural communities in California[5]. We then calculated the number of hectares that either were unchanged or increased in density category because of hydraulic fracturing-enabled production. We refer to areas that did not change categories as “not noticeably impacted,” areas that moved from the control group to a higher category as “newly impacted,” and areas that shifted from the low and medium categories to a higher category as experiencing “increased intensity” of production. We refer to the newly impacted and increased intensity areas collectively as “altered” areas. Table 5.3.1 summarizes how we categorize changes in well density.

5. Our categories differ from Fiehler and Cypher (2011) in two respects. First, Fiehler and Cypher had a gap between the medium and high categories: the medium category ended at 77 wells/km^2 and high began at 150 wells km^2; we reassigned the lower end of the high category as 77 wells/km^2 to eliminate the gap. Second, Fiehler and Cypher counted wells in study areas of around 0.648 km^2 in size while we estimated the number of wells/km^2 in a moving window of comparable size.

Table 5.3.1. Description of well density categories used in this study. We divided the effect of hydraulic-fracturing-enabled production on well density into three major categories: newly developed, increased intensity, and not noticeably impacted areas. The three categories are defined in terms of the types of shifts between density classes. We use blue, yellow, red and gray consistently to color-code the three categories throughout this chapter. For simplicity, we refer collectively to areas that were newly developed or increased in intensity as showing an increase in hydraulic fracturing, with the caveat that our results do not factor in areas that increased in well density due to hydraulic-fracturing-enabled-production, but not enough to move up a category.

	Category	**Change between density classes**
Altered	Newly developed	Control -> Low, Med, High
	Increased intensity	Low -> Med, High
		Med ->High
Unaltered	Either no change in well density, or no noticeable change in well density (that is, not enough to shift the density to a higher class).	Control-> Control Low->Low Med->Med High->High

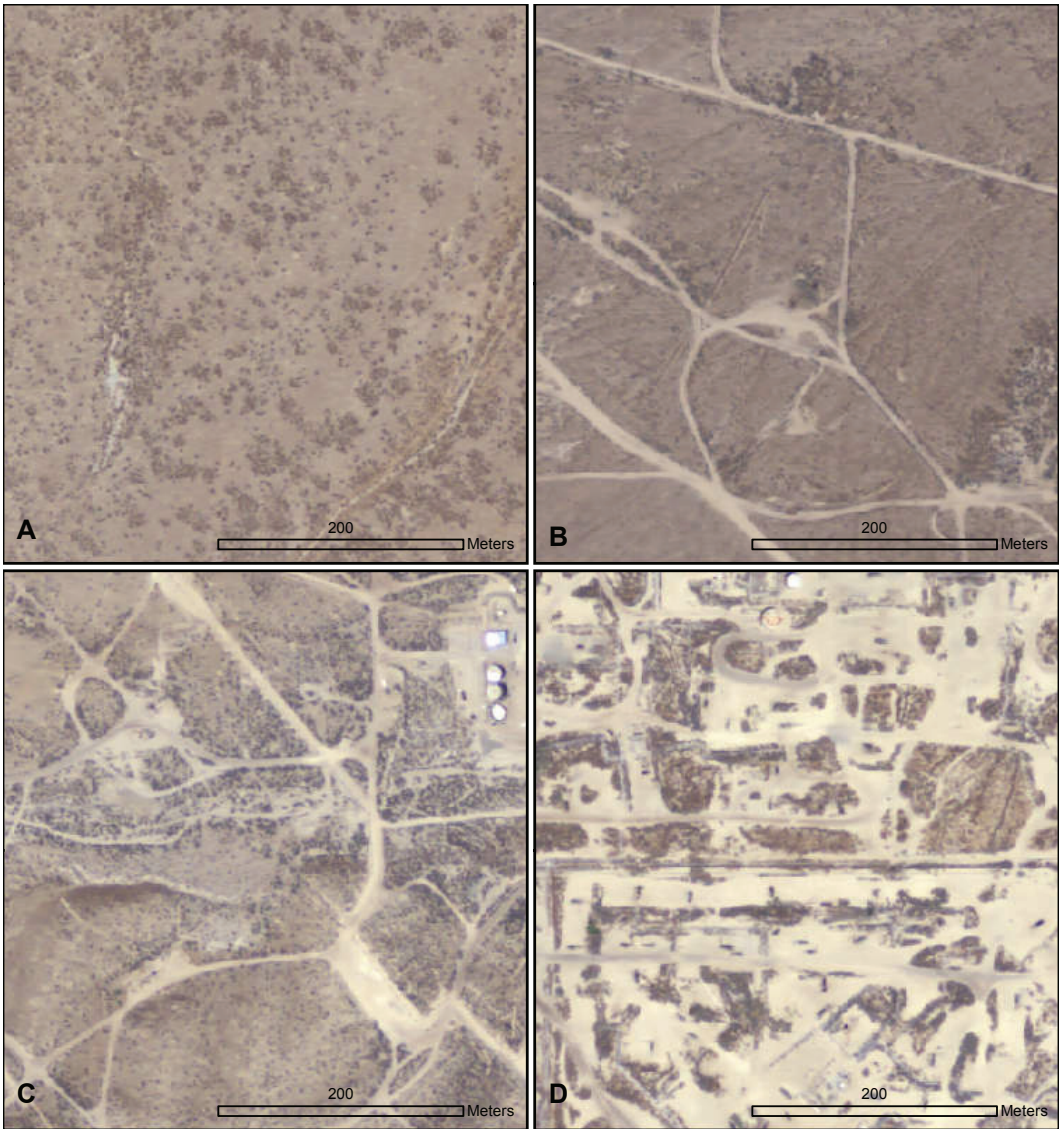


Figure 5.3.1. Aerial photos of each well-density category. The off-white areas are well pads, roads, and other unvegetated, highly disturbed areas. The gray, blotchy regions are vegetated areas that represent a natural habitat type. As well density increases, the amount of unvegetated land increases. (A) Control – less than one well per / km². (B) Low – 1-15 wells / km²). (C) Medium - 15-77 wells / km² (D) High - more than 77 wells / km².

We classified areas first by *land use* (developed, agricultural, or natural areas); for natural areas, we looked more closely at broad *land cover* types, which refer to functional types of vegetation: shrubland and grassland, forest and woodland, open water, and so forth (UCSB Biogeography Lab, 1998). We further subdivided land cover types into *natural communities*, which subdivides the state into common plant associations such as valley saltbush scrub, non-native grassland, and so forth (Holland 1986). There are more than

200 natural community categories; as a result, we focused on the four with more than 1,000 hectares of altered area plus two aquatic habitat types, and grouped the remainder under "other natural communities." Table 5.3.2. gives the categories and classifications we used in our assessment.

Table 5.3.2. Categories of land use, land cover, and natural communities used in this assessment.

Category	Classifications	Data Source
Land Use	1. Developed and other human use 2. Agricultural, introduced, or modified vegetation 3. Natural habitat, subdivided by the classifications given in Land Cover and Habitat Type	California DOC (2012)
Land Cover	1. Shrubland and grassland 2. Semi-desert 3. Forest and woodland 4. Open water 5. Polar, high montane, and barren	UCSB Biogeography Lab (1998)
Natural Community*	1. Valley saltbush scrub 2. Non-native grassland 3. Venturan coastal sage scrub 4. Buck brush chaparral 5. Water 6. Riparian and wetland 7. Other natural communities	Holland (1986)

** Some of our "Natural Community" groups are equivalent to the natural communities described in Holland (1986), while others (water, and riparian and wetland) group a number of Holland natural communities under one header.*

5.3.1.2.2. Results and Discussion of Quantitative Analysis of Well Stimulation Impacts to Habitat Loss and Fragmentation

We estimated that 33,000 hectares shifted to a higher well density category with hydraulic-fracturing-enabled oil production; of this, about 21,000 hectares (60%) was natural habitat. About 1% of California's land is developed for oil and gas production (with a well density greater than 1/km^2), compared to 5% for urban development and 14% for agriculture. About 3.5% of the habitat loss due to oil and gas production as a whole is attributable to hydraulic-fracturing-enabled activity.

The impacts of oil and gas production in general, and well stimulation in particular, are concentrated in a few areas of the state. Of the 33,000 hectares statewide that shifted to a higher well density category with hydraulic-fracturing enabled production, about 27,000 hectares (81%) were in Kern and Ventura Counties. About 8% of Kern and 4% of all lands in Ventura Counties are developed for oil and gas production (with a well density greater than 1/km^2).

The main habitat types disturbed by hydraulic fracturing-enabled production are valley saltbush scrub, non-native grassland, Venturan coastal sage scrub, and buck brush chaparral. These habitat types are mainly found in Kern and Ventura Counties. Twenty-four federally and/or state-listed threatened and endangered species have documented occurrences in oil fields where at least 200 hectares have reached a higher well-density class with hydraulic-fracturing-enabled production.

Question 1*: How has hydraulic fracturing-enabled production altered well density in California?*

Well density has increased in California due to hydraulic-fracturing-enabled production (Table 5.3.3). We estimate that about 33,000 hectares of land in the state have shifted into a higher-density category due to hydraulic-fracturing-enabled production (Table 5.3.3, red, yellow, and blue cells). 15,196 hectares were newly impacted by oil and gas development because of hydraulic-fracturing-enabled development (Table 5.3.3, blue cells). About 18,999 hectares already had wells present, but hydraulic fracturing enabled an increase in density (Table 5.3.3, yellow and red cells).

Table 5.3.3. The effect of hydraulic-fracturing-enabled production on well density in California oil and gas fields. The table shows the number of hectares in the state in a given category of well density without hydraulic-fracturing-enabled-production along the rows, and with hydraulic-fracturing-enabled-production along the columns. For example, 13,075 hectares in California had a control well density without hydraulically fractured wells, and a low well density with hydraulically fractured wells. Blue backgrounds indicate the area that was newly impacted by oil and gas production because of hydraulic-fracturing-enabled production. Yellow and red backgrounds show areas that were more intensively developed for oil and gas with hydraulic-fracturing enabled production. Gray backgrounds show the area where well density was not noticeably affected by hydraulic-fracturing-enabled production. The sum of blue, yellow, and red cells equals the total area altered by hydraulic-fracturing-enabled production.

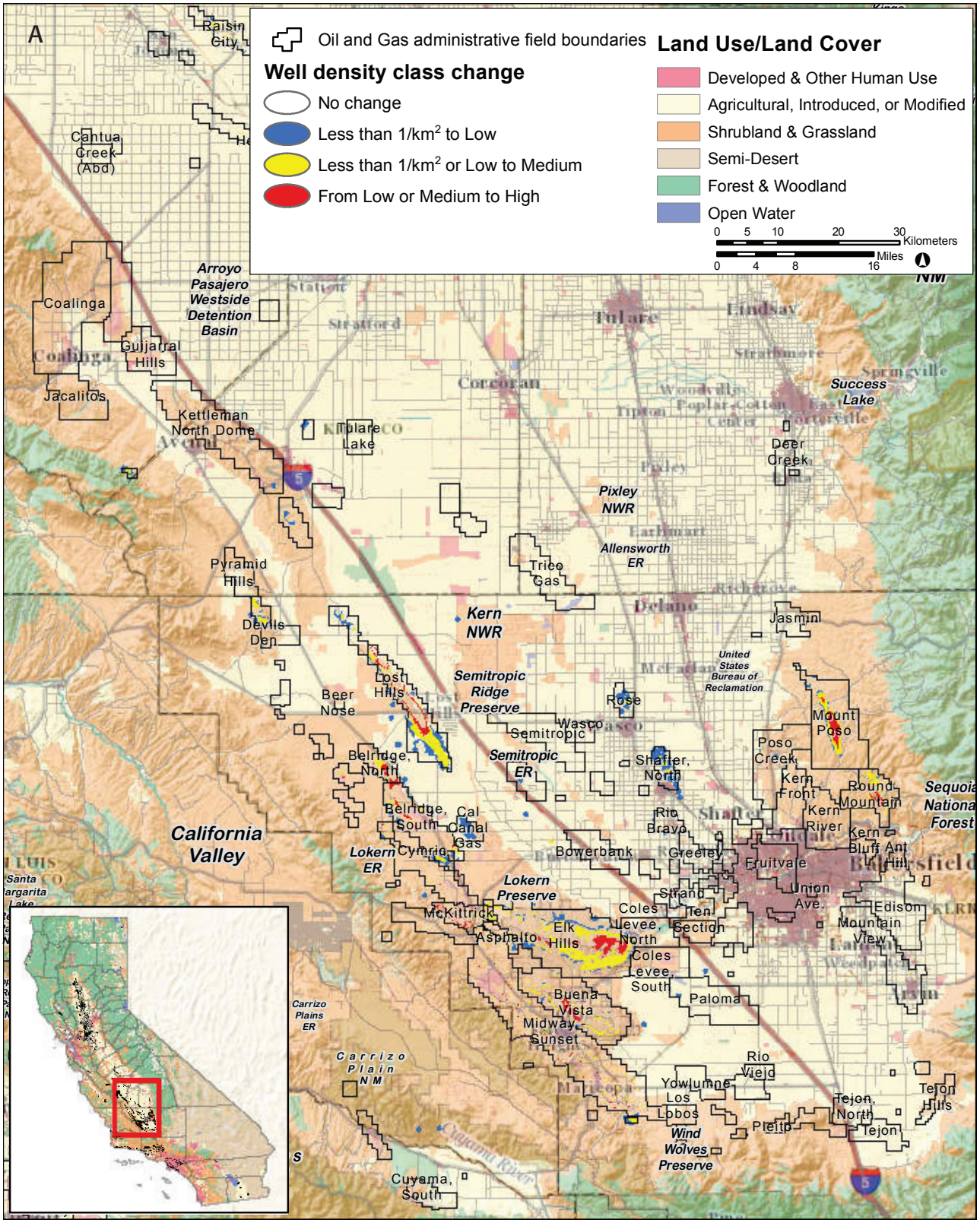
		Well Density With Hydraulic-Fracturing-Enabled Production (ha)			
		Control	Low	Medium	High
Background Well Density (ha)	Control	41,958,038	13,075	2,114	7
	Low		301,709	11,773	772
	Medium			70,044	5,308
	High				31,799

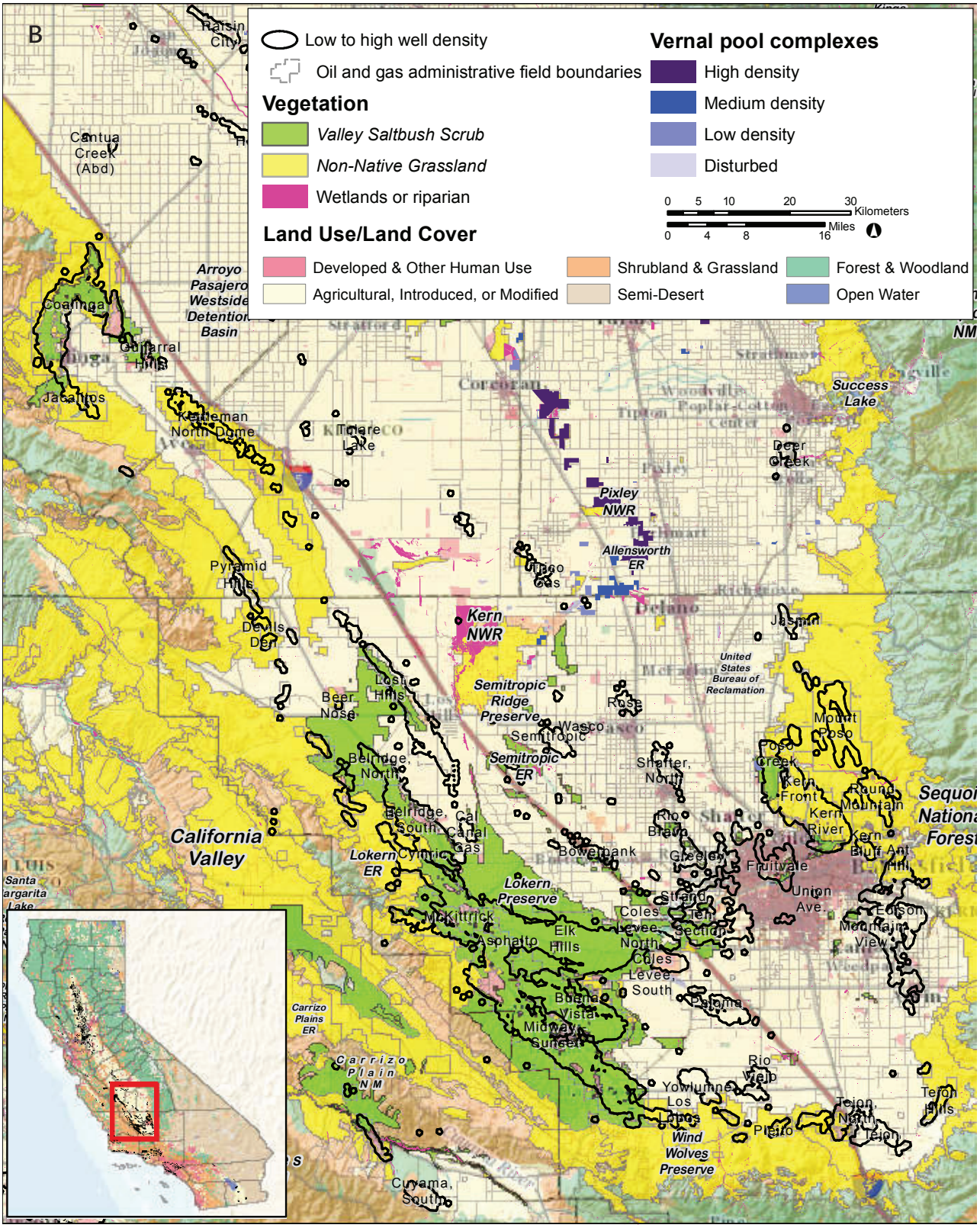
The majority of altered area in the San Joaquin Valley occurred around the southern perimeter of the valley in fields dominated by shrubland and grassland such as Elk Hills, Buena Vista, Midway-Sunset, Lost Hills, Mt. Poso and Round Mountain. Figure 5.3.2 (a) and Figure 5.3.3 (a). There are smaller amounts of altered habitat in the central portion of the valley where agriculture is the dominant land use in oil fields such as North Shafter and Rose.

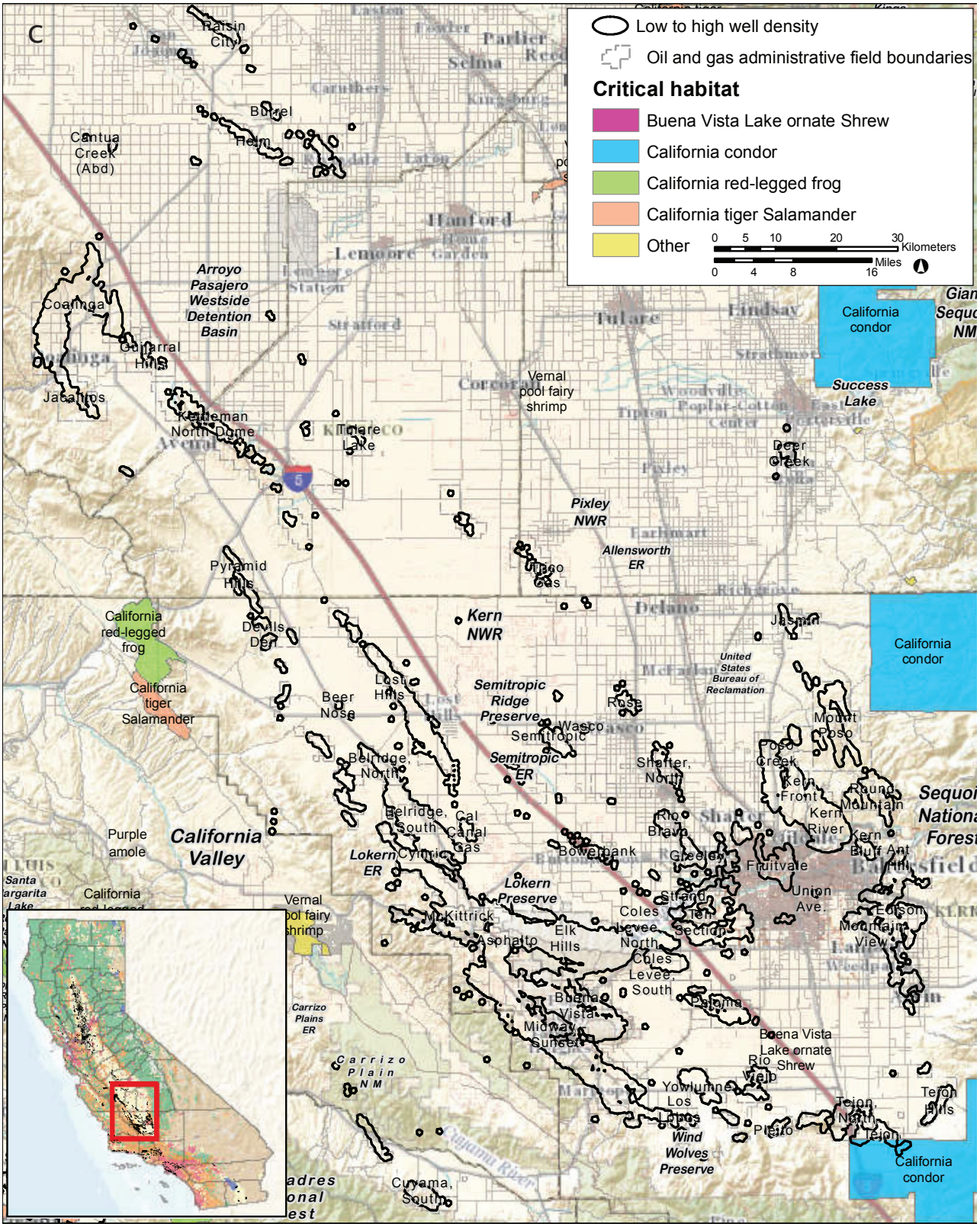
The inner core of fields such as Lost Hills and North and South Belridge Fields, where production of diatomite pools requires hydraulic fracturing, were considered unaltered (for the purposes of habitat quality) by well stimulation because they were already high-density regardless of hydraulic-fracturing-enabled-development. Lost Hills, North and South Belridge collectively represent 79% of reported hydraulic fracturing in the state (Volume I, Chapter 3, Table 3-1). Because these fields are also the location of intensively developed pools that do not require hydraulic fracturing, much of this area is already largely inhospitable to most native wildlife and vegetation, regardless of the added well density attributable to hydraulic fracturing. Thus, the additional impact of hydraulic fracturing to habitat degradation in these areas is probably minimal.

In Ventura County, the majority of altered area occurred in a string of three fields along the transverse mountain range: the Sespe, Ojai, and Ventura fields. Although the total well densities of the Ojai and Sespe are not very high, nearly all of the development is enabled by hydraulic fracturing. The Ventura field is a bit different as it already had a moderate level of development and hydraulic-fracturing-enabled-development increased the intensity. The portions of the Ojai and Sespe altered by hydraulic-fracturing-enabled-development overlap mostly with natural habitat; in the Ventura Field, the altered areas were mostly in urban and built-up land.

Appendix 5.B, Maps of Well Density in California, shows larger versions of these maps for the major hydrocarbon-producing basins of California.


A
Oil and Gas administrative field boundaries
Well density class change
No change
Less than 1/km² to Low
Less than 1/km² or Low to Medium
From Low or Medium to High
Land Use/Land Cover
Developed & Other Human Use
Agricultural, Introduced, or Modified
Shrubland & Grassland
Semi-Desert
Forest & Woodland
Open Water
0 5 10 20 30 Kilometers
0 4 8 16 Miles
Raisin City
Cantua Creek (Abd)
Arroyo Pasajero Westside Detention Basin
Coalinga
Guijarral Hills
Jacalitos
Kettleman North Dome
Tulare Lake
Pixley NWR
Allensworth ER
Pyramid Hills
Devils Den
Trico Gas
Kern NWR
Semitropic Ridge Preserve
Beer Nose
Lost Hills
Belridge, North
Belridge, South
Cal Canal Gas
Cymric
Semitropic
Semitropic ER
Wasco
Rose
United States Bureau of Reclamation
Jasmin
Mount Poso
Poso Creek
Kern Front
Kern River
Round Mountain
Kern Bluff
Ant Hill
Sequoia National Forest
Shafter, North
Rio Bravo
Bowerbank
Greeley
Fruitvale
Union Ave.
Edison
Mountain View
California Valley
Lokern ER
Lokern Preserve
McKittrick
Asphalto
Elk Hills
Coles Levee, North
Coles Levee, South
Strand
Ten Section
Paloma
Buena Vista
Midway-Sunset
Carrizo Plains ER
Carrizo Plain NM
Rio Viejo
Yowlumne
Los Lobos
Wind Wolves Preserve
Tejon, North
Tejon
Tejon Hills
Cuyama, South
Success Lake
Deer Creek
Tulare
Lindsay
Corcoran
Delano
Shafter
Bakersfield
Santa Margarita Lake


B
Low to high well density
Oil and gas administrative field boundaries
Vegetation
Valley Saltbush Scrub
Non-Native Grassland
Wetlands or riparian
Land Use/Land Cover
Developed & Other Human Use
Agricultural, Introduced, or Modified
Shrubland & Grassland
Semi-Desert
Forest & Woodland
Open Water
Vernal pool complexes
High density
Medium density
Low density
Disturbed
0 5 10 20 30 Kilometers
0 4 8 16 Miles
Raisin City
Cantua Creek (Abd)
Arroyo Pasajero Westside Detention Basin
Coalinga
Guijarral Hills
Jacalitos
Kettleman North Dome
Tulare Lake
Corcoran
Success Lake
Deer Creek
Pixley NWR
Allensworth ER
Pyramid Hills
Devils Den
Kern NWR
Jasmin
United States Bureau of Reclamation
Lost Hills
Beer Nose
Semitropic Ridge Preserve
Rose
Wasco Semitropic
Semitropic ER
Mount Poso
Poso Creek
Kern Front
Round Mountain
Kern River
Kern Bluff
Ant Hill
Belridge North
Belridge South
Cal Canal Gas
Shafter North
Rio Bravo
Bowerbank
Greeley
Fruitvale
Union Ave
Edison
Mountain View
California Valley
Lokern ER
Lokern Preserve
McKittrick
Asphalto
Elk Hills
Coles Levee North
Coles Levee South
Stand
Tenneco
Section 13
Paloma
Buena Vista
Midway Sunset
Carrizo Plains ER
Carrizo Plain NM
Rio Viejo
Yowlumne
Los Lobos
Wind Wolves Preserve
Tejon North
Tejon
Tejon Hills
Cuyama South
Santa Margarita Lake


C
Low to high well density
Oil and gas administrative field boundaries
Critical habitat
Buena Vista Lake ornate Shrew
California condor
California red-legged frog
California tiger Salamander
Other
0 5 10 20 30 Kilometers
0 4 8 16 Miles
Raisin City
Burrel
Helm
Cantua Creek (Abd)
Coalinga
Guijarral Hills
Jacalitos
Arroyo Pasajero Westside Detention Basin
Kettleman North Dome
Lemoore
Hanford
Corcoran
Tulare
Lindsay
Strathmore
Woodville
Tipton
Poplar-Cotton Center
Exeter
Farmersville
Visalia
Tulare Lake
Vernal pool fairy shrimp
Success Lake
Deer Creek
Pixley NWR
Allensworth ER
Tupco
Pyramid Hills
Devils Den
California red-legged frog
California tiger Salamander
Kern NWR
Delano
Jasmin
United States Bureau of Reclamation
Lost Hills
Beer Nose
Semitropic Ridge Preserve
Wasco
Semitropic
Semitropic ER
Rose
Shafter, North
Mount Poso
Poso Creek
Kern Front
Round Mountain
Kern River
Kern Bluff
Ant Hill
Sequoia National Forest
Belridge, North
Belridge, South
Cal Canal Gas
Cymric
Lokern ER
Bowerbank
Rio Bravo
Greeley
Fruitvale
Union Ave.
Edison
Mountain View
Purple amole
California Valley
Lokern Preserve
McKittrick
Asphalto
Elk Hills
Coles Levee North
Coles Levee South
Stand
Tenneco
Section 30
Buena Vista
Midway Sunset
Paloma
Buena Vista Lake ornate Shrew
Rio Bravo
Yowlumne
Los Lunas
Wind Wolves Preserve
Pleito
Tejon, North
Tejon
Tejon Hills
California condor
Carrizo Plains ER
Carrizo Plain NM
Cuyama, South
Santa Margarita Lake

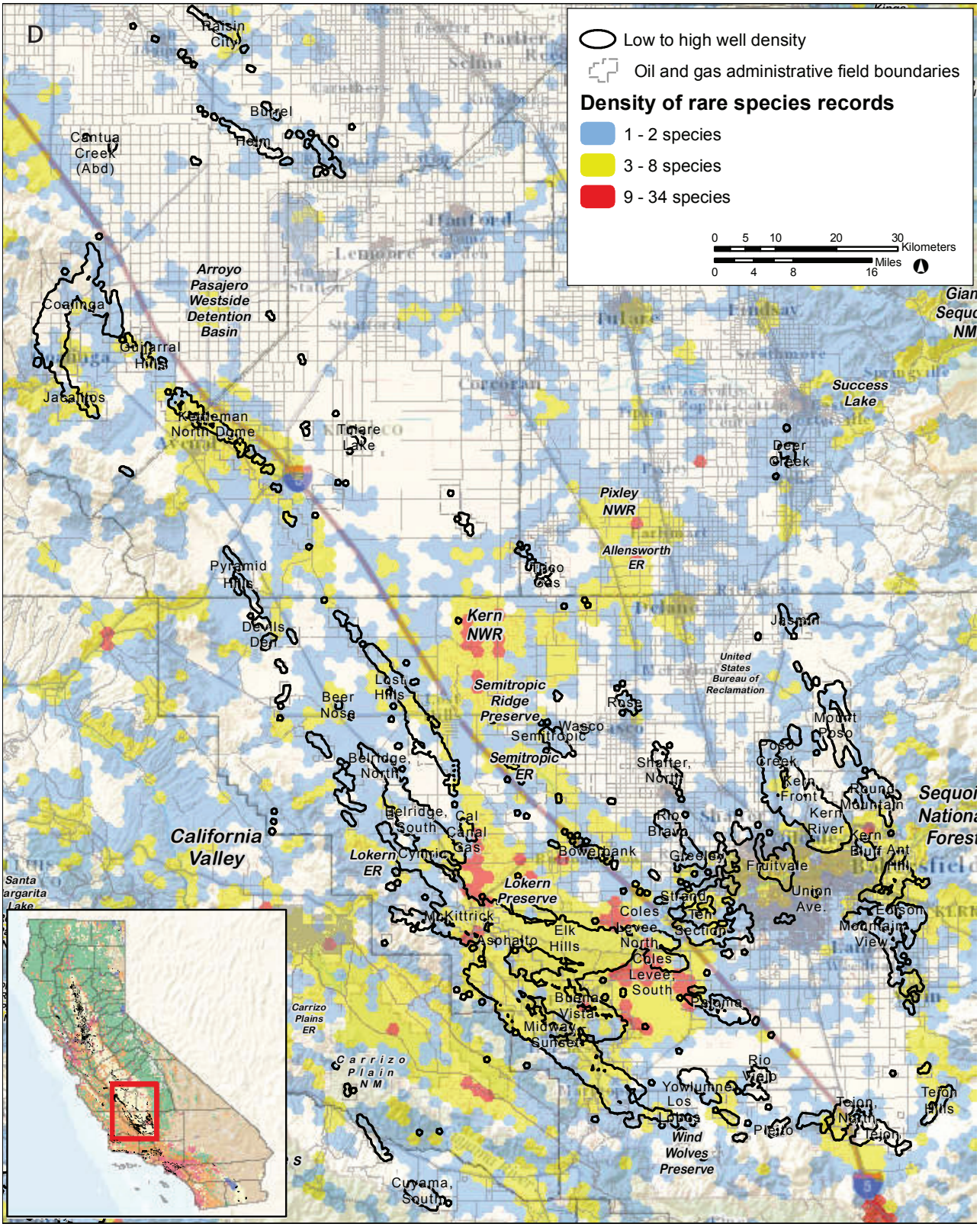
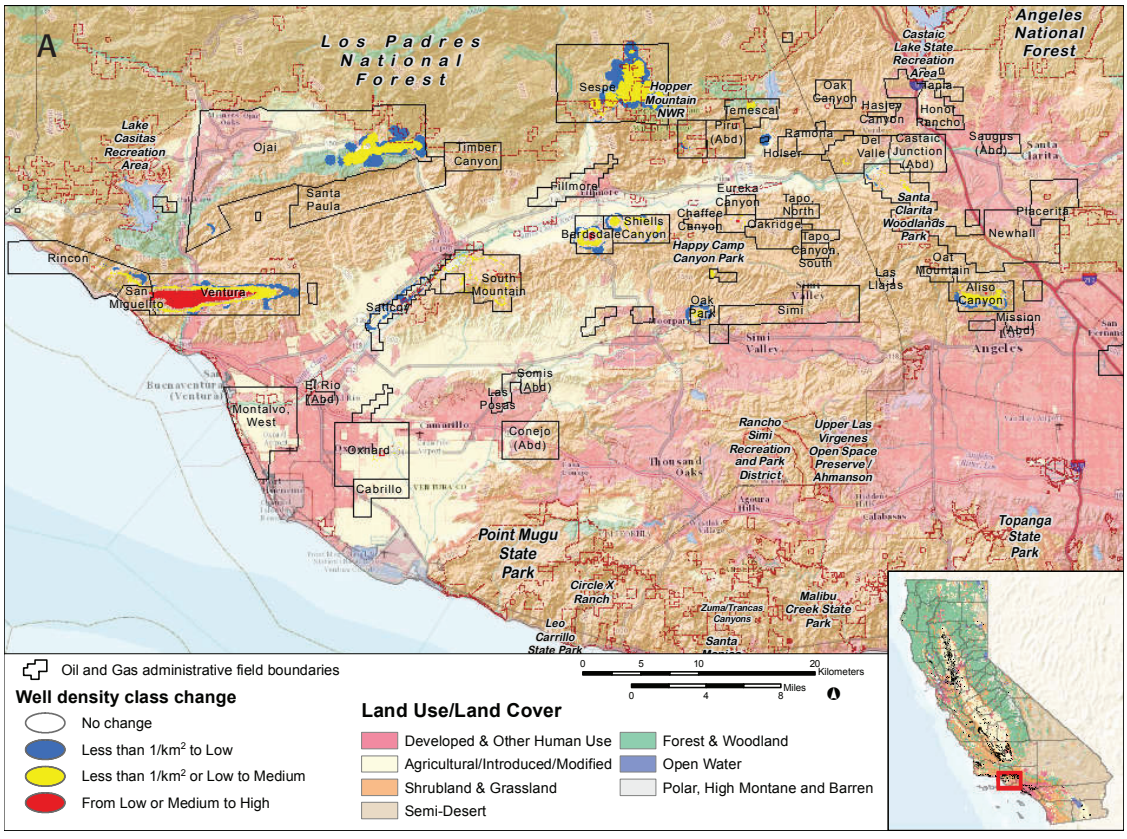
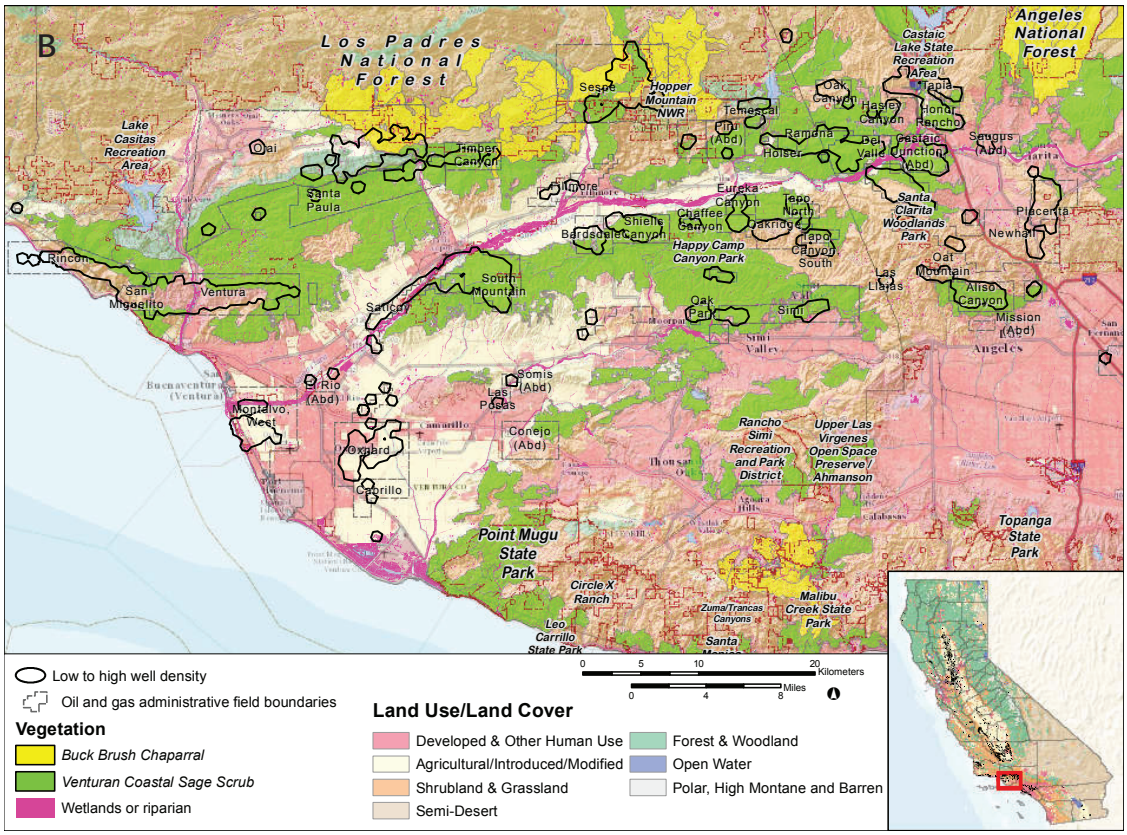
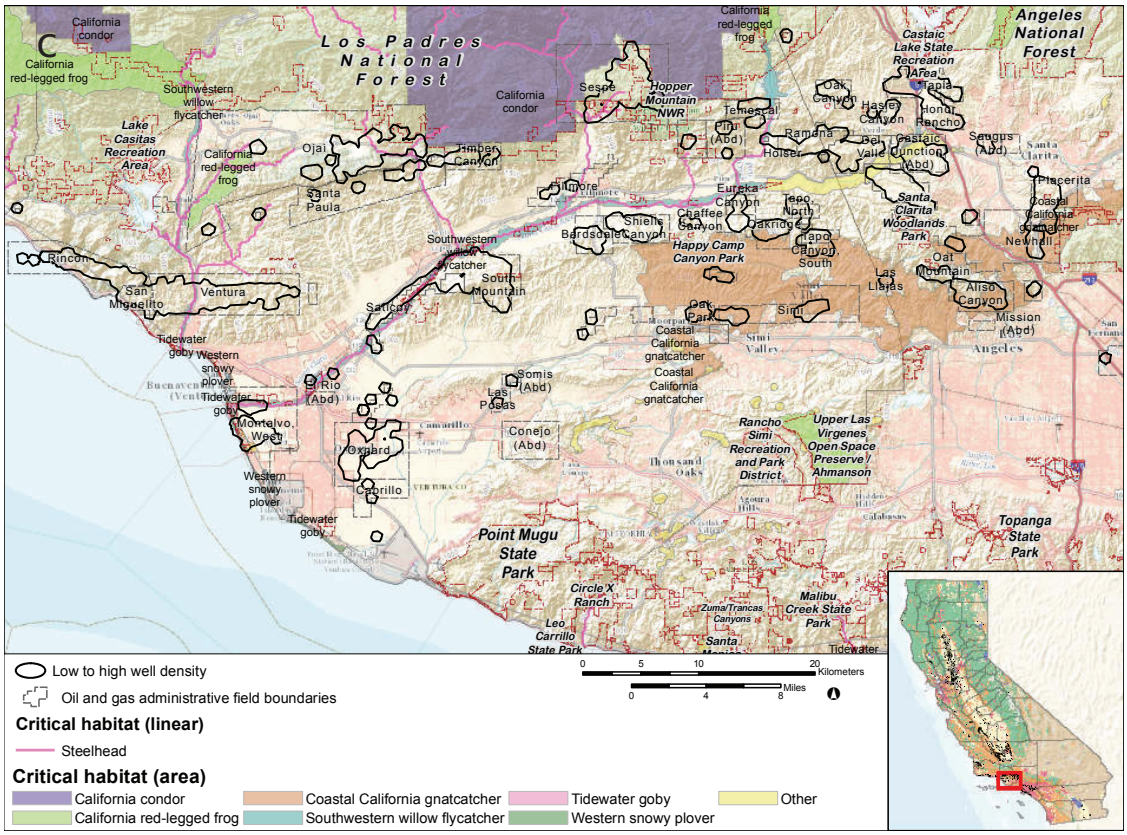

D
Low to high well density
Oil and gas administrative field boundaries
Density of rare species records
1 - 2 species
3 - 8 species
9 - 34 species
0 5 10 20 30 Kilometers
0 4 8 16 Miles
Raisin City
Buttel
Helm
Cantua Creek (Abd)
Arroyo Pasajero Westside Detention Basin
Coalinga
Guijarral Hills
Jacalitos
Kettleman North Dome
Tulare Lake
Success Lake
Deer Creek
Pixley NWR
Allensworth ER
Pyramid Hills
Devils Den
Kern NWR
Jasmin
United States Bureau of Reclamation
Lost Hills
Beer Nose
Semitropic Ridge Preserve
Rose
Wasco Semitropic
Semitropic ER
Mount Poso
Poso Creek
Shafter, North
Kern Front
Round Mountain
Kern River
Belridge, North
Belridge, South
Cal Canal Gas
Rio Bravo
Bowerbank
Greeley
Fruitvale
Bluff Ant Hills
California Valley
Lokern ER
Cymric
Lokern Preserve
Union Ave.
Strand
Coles Levee, North
Ten Section
Loflon
McKittrick
Asphalto
Elk Hills
Mountain View
Coles Levee, South
Paloma
Buena Vista
Midway Sunset
Carrizo Plains ER
Carrizo Plain NM
Rio Viejo
Yowlumne
Los Lobos
Tejon, North
Tejon
Tejon Hills
Wind Wolves Preserve
Cuyama, South
Santa Margarita Lake

Figure 5.3.2. Maps of the San Joaquin Basin showing the increase in well density attributable to hydraulic fracturing-enabled development and key ecological features (a) Change in well density due to hydraulic fracturing-enabled production. Colors show areas that increased in well density due to fracturing-enabled production. Blue indicates areas that increased to low density with the addition of hydraulically fractured wells, yellow shows areas that increased to medium, and red indicates areas that increased to high well density. (b) Selected habitat types for the San Joaquin Basin, including dominant types (non-native grassland and valley saltbush scrub), wetland and riparian habitat, and vernal pools complexes are indicated. Black outlines indicate areas developed for oil and gas production (with at least 1 well per km²). (c) Critical habitat in the region, shown as colored polygons. Despite a high concentration of threatened and endangered species, little critical habitat has been designated in the San Joaquin Valley. Critical habitat for the Buena Vista Lake ornate shrew is south of Bakersfield, it is labeled to but too small to be visible. Black outlines indicate areas developed for oil and gas production. (d) Density of rare species records recorded in the CNDDB. Black outlines indicate areas developed for oil and gas production. Data sources: DOGGR, 2014a; 2014b; 2014c; UCSB Biogeography Lab, 1998; California DOC, 2012; USFWS, 2014b, Biogeographic Data Branch DFW, 2014.




B
Los Padres National Forest
Angeles National Forest
Lake Casitas Recreation Area
Castaic Lake State Recreation Area
Hopper Mountain NWR
Santa Paula
Ojai
Timber Canyon
Fillmore
Santa Clarita Woodlands Park
Happy Camp Canyon Park
Rincon
San Miguelito
Ventura
Saticoy
South Mountain
Oak Park
Simi
Simi Valley
Las Llajas
Oak Mountain
Alisso Canyon
Mission (Abd)
Placerita
Newhall
Angeles
Somis (Abd)
Las Posas
Montalvo, West
El Rio (Abd)
Oxnard
Camarillo
Conejo (Abd)
Cabrillo
Rancho Simi Recreation and Park District
Upper Las Virgenes Open Space Preserve / Ahmanson
Point Mugu State Park
Circle X Ranch
Leo Carrillo State Park
Zuma/Trancas Canyons
Malibu Creek State Park
Topanga State Park
Low to high well density
Oil and gas administrative field boundaries
Vegetation
Buck Brush Chaparral
Venturan Coastal Sage Scrub
Wetlands or riparian
Land Use/Land Cover
Developed & Other Human Use
Agricultural/Introduced/Modified
Shrubland & Grassland
Semi-Desert
Forest & Woodland
Open Water
Polar, High Montane and Barren
Kilometers
Miles


C
California condor
California red-legged frog
Southwestern willow flycatcher
Los Padres National Forest
Angeles National Forest
Lake Casitas Recreation Area
Castaic Lake State Recreation Area
Hopper Mountain NWR
Santa Paula
Ojai
Timber Canyon
Fillmore
Santa Clarita Woodlands Park
Happy Camp Canyon Park
Coastal California gnatcatcher
Tidewater goby
Western snowy plover
Rincon
San Miguelito
Ventura
Saticoy
South Mountain
Oak Park
Simi
Simi Valley
Las Llajas
Oak Mountain
Alisso Canyon
Mission (Abd)
Placerita
Newhall
Angeles
Somis (Abd)
Las Posas
Montalvo, West
El Rio (Abd)
Oxnard
Camarillo
Conejo (Abd)
Cabrillo
Rancho Simi Recreation and Park District
Upper Las Virgenes Open Space Preserve / Ahmanson
Point Mugu State Park
Circle X Ranch
Leo Carrillo State Park
Zuma/Trancas Canyons
Malibu Creek State Park
Topanga State Park
Low to high well density
Oil and gas administrative field boundaries
Critical habitat (linear)
Steelhead
Critical habitat (area)
California condor
California red-legged frog
Coastal California gnatcatcher
Southwestern willow flycatcher
Tidewater goby
Western snowy plover
Other
Kilometers
Miles

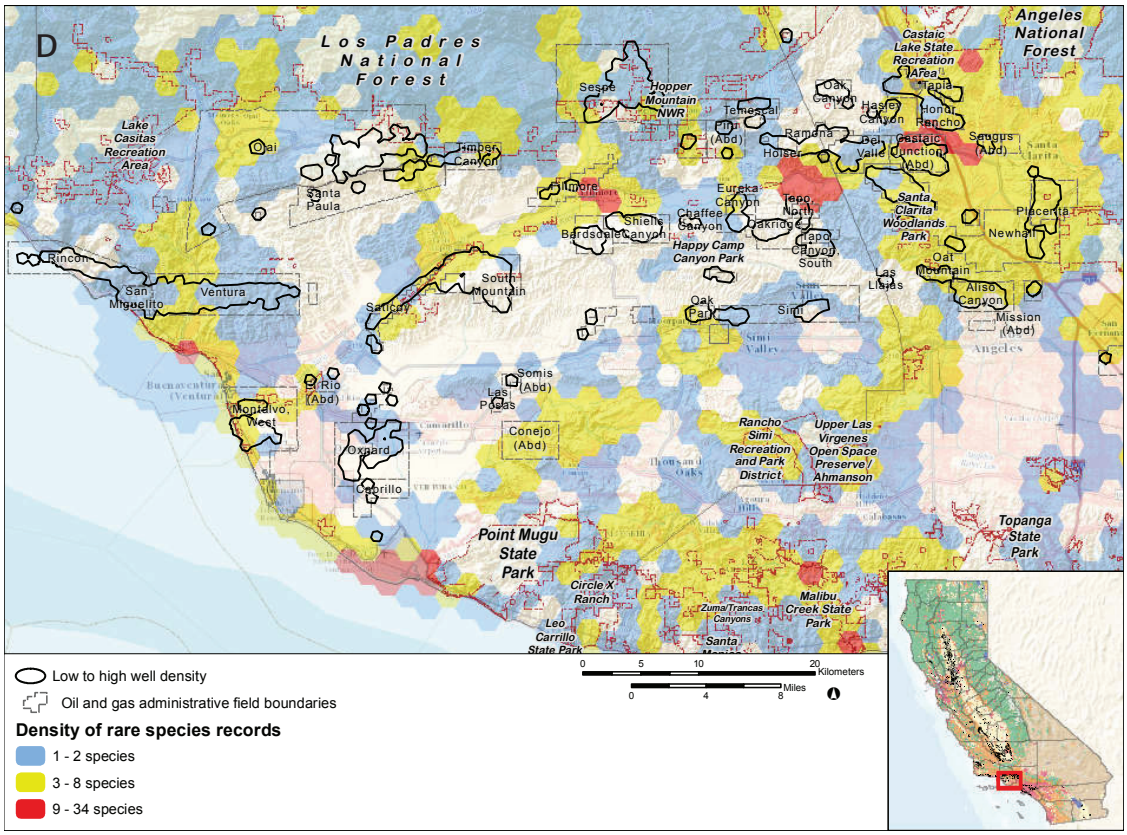


Figure 5.3.3. Maps of the Ventura Basin showing the increase in well density attributable to hydraulic fracturing-enabled development and key ecological features. (a) Change in well density due to hydraulic fracturing-enabled production. Blue indicates an area changed from control to low or medium density with the addition of hydraulically fractured wells. Yellow shows areas that changed from low to medium or high. Red indicates areas that changed from medium to high. Shrub and grassland were the land cover types most impacted by fracturing-enabled production. (b) Vegetation in the Ventura Basin. Dominant habitat types (buck brush chaparral and Venturan coastal sage scrub), wetland and riparian habitat are indicated. Black outlines indicate areas developed for oil and gas production. (c) Designated critical habitat shown as colored polygons. Critical habitat for California condor and steelhead salmon overlap with impacted areas. Black outlines indicate areas developed for oil and gas production. (d) Density of rare species records recorded in the CNDDB. Black outlines indicate areas developed for oil and gas production. Data sources: DOGGR, 2014a; 2014b; 2014c; UCSB Biogeography Lab, 1998; California DOC, 2012; USFWS, 2014b, Biogeographic Data Branch DFW, 2014.

Question 2: *How are the areas with increased well density distributed across habitat types and counties in California?*

Of the 33,000 hectares in the state affected by hydraulic-fracturing-enabled production, 60% was natural habitat, 32% was agricultural, and 8% was urban, built-up, or barren. Nearly 90% of natural habitat impacted by hydraulic fracturing was in Kern and Ventura Counties, 64% in Kern and 24% in Ventura (see Table 5.3.4). This finding motivated us to focus principally on Kern and Ventura Counties for the remainder of our assessment of the effect of hydraulic fracturing on habitat loss and fragmentation.

Table 5.3.4. Hectares by county and all of California for areas developed for oil and gas production (with a well density of at least 1 well per km^2), altered area (areas that shifted up in well density category with hydraulic fracturing-enabled production), and altered natural habitat (areas classified as natural habitat that shifted up in well density category with hydraulic fracturing-enabled production). All numbers rounded to the hundreds place; some numbers may not sum due to rounding.

	Developed Area		**Altered Area**		**Altered Natural Habitat**	
	Hectares	% of Column	Hectares	% of Column	Hectares	% of Column
Kern	163,100	37%	20,100	61%	13,400	64%
Ventura	23,200	5%	6,900	21%	5,000	24%
All Other Counties	250,300	57%	6,000	18%	2,500	12%
State Total	436,600	100%	33,000	100%	20,900	100%

The habitat types that were most impacted were those that occur in oil fields of Kern and Ventura Counties where a large proportion of wells are stimulated: valley saltbush scrub, non-native grassland, Venturan coastal sage scrub, and buck brush chaparral all had over 1,000 hectares increase in well density. The maps in Figure 5.3.2 (b) and Figure 5.3.3(b) show the locations of the key altered communities in the southern San Joaquin and Ventura Counties. Figure 5.3.4 shows impacts to land use and habitat types broken out by county.

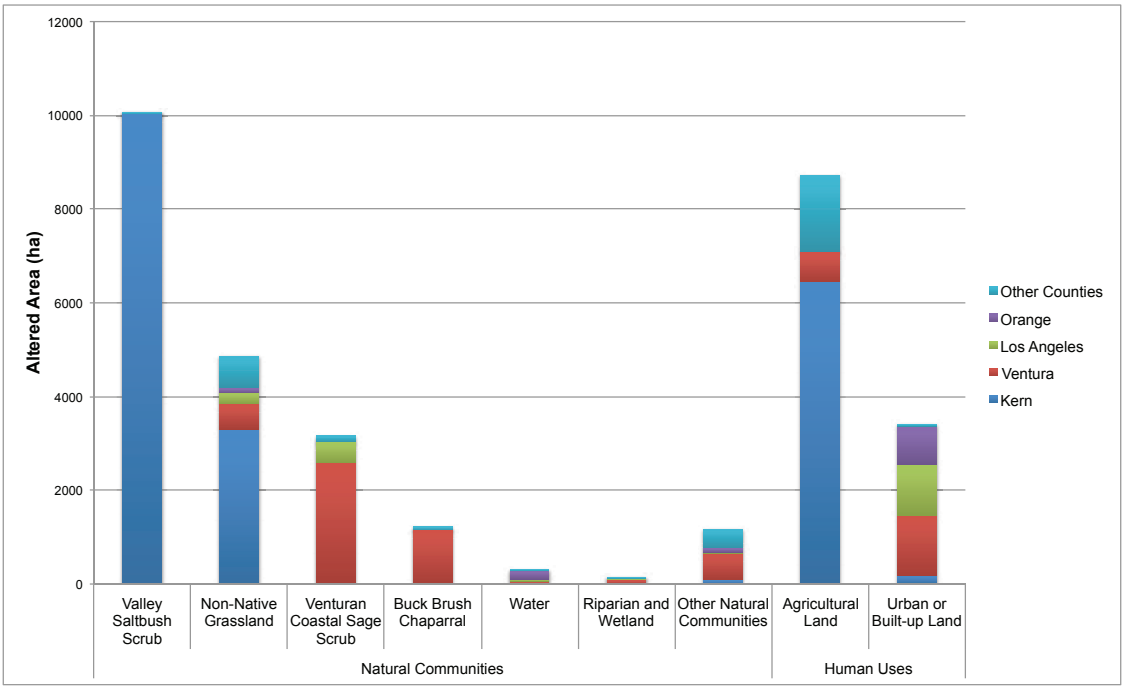


Figure 5.3.4. Land use and habitat types impacted by hydraulic-fracturing-enabled production in California. A large amount of the area that increased in well density due to hydraulic fracturing is agricultural or urban land already highly disturbed by humans and generally unsuitable as habitat for native wildlife and vegetation. Areas designated as natural communities are important habitat for wildlife and vegetation. The counties that had the greatest amount of impacted area are color-coded. The data used to generate this figure are in Appendix 5.D, Table 5.D.2.

The rate of natural habitat areas newly impacted by hydraulic-fracturing-enabled production is a larger proportion of recent activity (from Oct 1, 2012 – Sep. 30, 2014). Of the 1,400 hectares that were newly developed for oil and gas production during the period from Oct. 1, 2012 to Sep. 30, 2014, about 300 hectares (18%) could be attributed to hydraulic fracturing.

Habitat loss caused by hydraulic-fracturing-enabled-production is highly localized and has disproportionate effects in a few areas and for a few habitat types. For valley saltbush scrub, 6% of its statewide extent was impacted by hydraulic-fracturing-enabled-production, and 2% for Venturan coastal sage scrub (Appendix 5.D, Table 5.D.1). In proportion to the total amount of habitat in the state, the amount of habitat impacted by hydraulic-fracturing-enabled-production is small: on the order of less than one-tenth of one percent.

The area of altered aquatic habitat was quite small. Statewide, there were about 300 hectares of altered open water habitat and 140 of riparian and wetland habitat. While the impacts to aquatic habitats was small in terms of total area affected by hydraulic-fracturing-enabled-production, even small impacts to aquatic areas merit consideration because they are generally considered high-value habitats and are accorded special protections under the Federal Clean Water and Coastal Zone Management Acts, as well as the State Lake and Streambed Alteration, Porter-Cologne Water Quality Act, and California Coastal Acts. Most of the altered riparian and wetland habitat was in Ventura County, followed by Los Angeles County (Appendix 5.D, **Table 5.D.2**(a)). For open water, altered areas were concentrated in Orange County, followed by Ventura County. Despite the high intensity of hydraulic fracturing activity in the San Joaquin Valley, there is little impact in terms of increased well density in aquatic habitat because the two do not overlap geographically. Potential impacts to aquatic habitats are discussed further in the chapter in the sections on fluid discharges and water use associated with well stimulation, in Sections 5.3.3 and 5.3.4, below.

Our results should be interpreted with caution, as the resolution of the data on natural communities is coarse relative to the size of a well pad. The natural community data is given on a scale of tens to 400 hectares (from one-tenth to four square kilometers). Well pads for a single well are typically smaller than a tenth of a square kilometer (SHIP, 2014). Therefore, when we find that well density increased in an area of a given habitat type, this may mean that the wells were in the vicinity of these habitat types, but not directly in them.

Question 3*: What special-status species occurred in the vicinity of oil fields highly impacted by well stimulation?*

Under the Federal and California Endangered Species Acts (ESA and CESA), threatened and endangered species, referred to collectively as "listed" species, are entitled to special legal protections. Species are listed as endangered because they are at risk of extinction; they are listed as threatened because they are likely to become endangered. In Table 5.3.5 we identify threatened and endangered species with occurrences recorded in the California Natural Diversity Database (CNDDB) on or within 2 km of oil and gas fields with at least 200 hectares impacted by hydraulic fracturing.

Table 5.3.5. Number of occurrences of listed species within 2 km of a field with at least 200 hectares of altered habitat. Table based on detections of rare species submitted to the California Natural Diversity Database (Biogeographic Data Branch DFW, 2014).

San Joaquin kit fox (*Vulpes macrotis mutica*)	234
Nelson's antelope squirrel (*Ammospermophilus nelsoni*)	189
blunt-nosed leopard lizard (*Gambelia sila*)	78
giant kangaroo rat (*Dipodomys ingens*)	68
Kern mallow (*Eremalche kernensis*)	32
Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*)	15
least Bell's vireo (*Vireo bellii pusillus*)	13
coastal California gnatcatcher (*Polioptila californica californica*)	11
California jewelflower (*Caulanthus californicus*)	4
Bakersfield cactus (*Opuntia basilaris var. treleasei*)	3
California red-legged frog (*Rana draytonii*)	3
giant garter snake (*Thamnophis gigas*)	3
San Joaquin woollythreads (*Monolopia congdonii*)	3
Santa Ana sucker (*Catostomus santaanae*)	3
southern steelhead - southern Calif. DPS (*Oncorhynchus mykiss irideus*)	3
Swainson's hawk (*Buteo swainsoni)*	3
Buena Vista Lake ornate shrew (*Sorex ornatus relictus*)	2
California condor (*Gymnogyps californianus*)	2
Ventura Marsh milk-vetch (*Astragalus pycnostachyus* var. *lanosissimus*)	2
California Orcutt grass (*Orcuttia californica*)	1
slender-horned spineflower (*Dodecahema leptoceras*)	1
southwestern willow flycatcher (*Empidonax traillii extimus*)	1
tidewater goby (*Eucyclogobius newberryi*)	1
unarmored threespine stickleback (*Gasterosteus aculeatus williamsoni*)	1
Total	**676**

An important indicator of valuable habitat is whether it has been designated as critical habitat for the recovery of a federally listed species. Critical habitat should be taken as a conservative indicator of valuable habitat; that is, there are likely to be habitats necessary for the survival of endangered species that have not been designated as critical habitat due to the legal and administrative difficulties in finalizing the process. The United States Fish and Wildlife Service (USFWS) has designated critical habitat for only 44% of all listed species in the U.S.

The only designated critical habitat in the southern San Joaquin Valley is for the Buena Vista Lake ornate shrew. Four small patches on the scale of a few square kilometers each are scattered through the southern portion of the valley in the vicinity of Coles Levee North and South, Buttonwillow Gas, Semitropic, and Semitropic Gas fields. Little to no

well stimulation occurs in these fields; the only reported hydraulic fracturing events in these five fields were two in the Semitropic field in 2012 (Volume I, Appendix M) and four notices of planned jobs at Coles Levee North (DOGGR, 2015).

Critical habitat has been designated for a number of species in Ventura County. Areas where substantial amounts of hydraulic-fracturing-enabled production has taken place in the Ojai and Sespe fields overlap with critical habitat for the California condor (*Gymnogyps californianus*) and steelhead salmon (*Oncorhynchus mykiss irideus)* (Figure 5.3.3c).

5.3.2. Human Disturbance Can Facilitate Colonization by Invasive Species

Hydraulic-fracturing-enabled production, like any other oil and gas production, can facilitate the introduction of invasive species, including non-native species (Hobbs and Huenneke, 1992). This occurs because human disturbances such as clearing and levelling land tend to open new niches, and humans and their vehicles can act as vectors for colonizers (Didham et al. 2005). Colonization by invasive species would largely be an indirect impact of well stimulation, given that most of the surface disturbance and vehicle traffic not directly in the service of well stimulation, but there would be some truck traffic that would be directly related to transporting materials and workers to implement a stimulation operation.

Invasive species are defined as non-native organism that reproduce and spread rapidly. They are typically habitat generalists and they frequently displace native species (Rejmánek and Richardson, 1996; Belnap, 2003; Coffin, 2007; Jones et al., 2014). Among plants, these species usually are typical of early successional stages in vegetation communities. Thus, any soil disturbances such as grading, disking, earthmoving, or vegetation clearing result in conditions that favor invasive species (Tyser and Worley, 1992; Gelbard and Belnap, 2003). In oilfields, such activities also can create novel micro-habitats such as borrow areas that collect moisture, berms along roads and around tank settings, and so forth, that provide colonization opportunities for species not native to an area. In the Elk Hills oilfield, the diversity of grasses and forbs (both non-native and native) increased on higher intensity oilfield plots, probably due to the increase in micro-habitats (Fiehler and Cypher, 2011). Also, seeds of species not native to an area are commonly transported in on equipment, vehicles, and boots, further increasing the opportunities for colonization.

Non-native animals also are able to colonize areas disturbed by humans. Rodents such as rats and house mice are common around developments. In western Kern County, Spiegel and Small (1996) found that house mice were extremely abundant in highly developed oilfields, but did not occur in nearby undisturbed habitat. Fiehler and Cypher (2011) found that bird abundance and species richness increased with level of oilfield development. They attributed this to increased contact between areas of intact habitat and human-disturbed areas, increased structural diversity resulting from the presence of facilities such as buildings, facilities, power lines, and pump jacks, and also to increased

vegetation diversity both from colonization by non-native plants and landscape plantings. They also found that non-native bird species were more abundant in highly developed areas whereas certain sensitive native species were much less abundant. In the San Joaquin Valley, another potential concern is colonization by non-native red foxes. This species has been increasing in this region, particularly in human-altered areas where its natural predator, the coyote, is less abundant (B. Cypher, CSU-Stanislaus, pers. observ.). Red foxes can compete with and even occasionally kill endangered San Joaquin kit foxes (Ralls and White, 1995; Cypher et al., 2001; Clark et al., 2005).

Occasionally, anthropogenic disturbances can benefit native species, including rare or sensitive species. In western Kern County, a federally threatened plant, Hoover's wooly-star (*Eriastrum hooveri*) quickly colonized disturbed sites and was commonly found on abandoned roads and well pads (Hinshaw et al., 1998; Holmstead and Anderson, 1998). Also in western Kern County, endangered blunt-nosed leopard lizards (*Gambelia sila*) commonly used dirt roads for foraging and movements in areas where dense ground cover impeded such activities (Warrick et al., 1998).

5.3.3. Discharges of Wastewater and Stimulation Fluids Can Affect Wildlife and Vegetation

The discussion in this chapter on discharges of fluids summarizes information presented in Chapter 2, with an expanded discussion of the literature relevant to assessing potential impacts to wildlife and vegetation. We review the potential pathways for release of fluids to the environment, the ecotoxicology of well stimulation fluids and wastewater, and consider the potential impacts of fluid releases to terrestrial, freshwater and marine ecosystems. Discharges of fluids can be a direct or indirect impact of well stimulation. The brines and hydrocarbons produced from the formation are part of any oil and gas production and are considered an indirect impact, while the a release to the environment of a stimulation fluid is a direct impact of well stimulation.

5.3.3.1. Potential Pathways for Release of Fluids to the Environment

Discharges of fluids related to well stimulation can occur intentionally through discharges of waste products to the surface, or by accidental spills and leaks. Chapter 2, Figure 2.6.1 shows surface (and near-surface) contaminant release mechanisms of concern in California related to stimulation, production, and wastewater management and disposal activities. The additives for stimulation fluids and proppant are typically transported by truck to a stimulation site (see Chapter 2, 2.4.3, "Evaluation of the Use of Additives in Stimulation Fluids," for more detail). They are diluted with water and injected into the stimulated well. Some portion of the stimulation fluids returns to the surface, mixed with hydrocarbons, formation water and possibly well clean-out fluids (see Chapter 2 Section 2.5.2, "Description of Wastewaters Generated by Well-Stimulation Operations").

The fluid produced from a well that remains after the marketable hydrocarbons are separated out is referred to as wastewater. For the purposes of this report, we are interested in any release of stimulation fluids to the environment as a direct impact of well stimulation. We are also interested in discharge of wastewater from stimulated wells to the environment, whether or not it contains stimulation fluids, as an indirect effect of well-stimulation enabled production.

Stimulation fluids and wastewater can potentially come into contact with wildlife and vegetation in a number of ways. Accidental releases can occur at any stage of the process, from transport of chemicals to the site, at the site during a stimulation operation, through an underground pathway, or once the fluids return to the surface after well completion. Wastewater can also be legally discharged to the terrestrial or freshwater environment under certain conditions to unlined surface pits, used for groundwater discharge, or applied to agricultural land for irrigation. In federal waters, treated wastewater can legally be discharged to the ocean.

5.3.3.1.1. Exposure to Stimulation Fluids and Wastewater in Land and Freshwater Ecosystems

Potential routes of environmental exposure to hydraulic fracturing chemicals include accidental spills and intentional discharges to surface storage ponds. Outside of California, Bamberger and Oswald (2012) documented a number of observations of harm to livestock, domestic animals, and wildlife that correlated with surface spills or intentional surface applications of wastewater from hydraulically fractured wells; however, these case studies were analyzed retrospectively through interviews, veterinary reports and other sources, and did not distinguish hydraulic fracturing flowback from produced water, so they cannot be taken as definitive evidence of direct harm from hydraulic fracturing operations.

Wildlife can suffer negative effects or mortality by drinking from or immersing themselves in wastewater storage or disposal ponds (Ramirez, 2010; Timoney and Ronconi, 2010). In the limited studies available of ecological impacts of oil field activity in California, there are a few documented cases of giant kangaroo rats, blunt-nosed leopard lizards and San Joaquin kit foxes drowning in accidental spills of oil and oil-laden wastewater (Kato and O'Farrell, 1986; O'Farrell and Kato, 1987). Suter et al. (1992) examined the elemental content of fur samples from San Joaquin Kit Foxes inhabiting two oil fields (one active, one inactive), and two control areas. They found that foxes on the developed sites had elevated levels of a number of elements which may be attributable to oil field materials. However, their results must be interpreted with caution because of flaws the authors themselves acknowledge in sampling design and statistical methods.

As described in Chapter 2, Section 2.5, discharge of wastewater to percolation pits, also called evaporation-percolation ponds, is the most commonly reported disposal method for stimulated wells in California. Percolation pits are primarily regulated by the state's nine

Regional Water Quality Control Boards. Much of the state's well stimulation takes place within the jurisdiction of the Central Valley Regional Water Quality Control Board. Within its jurisdiction, wastewater can legally be disposed of in percolation pits with a permit from the regional water board. However, it was recently found that an estimated 36% of sumps have been operating without the necessary permits (Holcomb, 2015). The Central Valley Regional Water Board requires that the fluid in the pits meet certain water quality standards for salinity (measured as electrical conductivity), chlorides, and boron. Oil field wastewater that exceeds the salinity thresholds may be discharged in percolation pits, or to local streams or ponds "if the discharger successfully demonstrates to the Regional Water Board in a public hearing that the proposed discharge will not substantially affect water quality nor cause a violation of water quality objectives." There is no testing required, or thresholds specified, for other contaminants. However, oil field wastewater typically contains other chemicals such as volatile organic compounds (VOCs), benzene, and naturally occurring radioactive material (NORM) that are of concern for human and environmental health.

Based on information obtained from the Central Valley Regional Water Quality Control Board and the State Water Resources Control Board, there are 950 known evaporation-percolation ponds in eight California counties, listed in Table 5.3.5 (Borkovich 2015a and b, CVRWQCB 2015). In Kern County, there were 484 active pits, 221 inactive, and 138 of unknown status, for a total of 843. There were no sump locations in Ventura County in the datasets we obtained. However, these datasets must be treated with caution as likely representing a minimum, but not necessarily a comprehensive list of percolation pit locations in the state. Chapter 2 discusses the caveats for these datasets.

Table 5.3.5. Reported sump locations in California. Locations were coded by status: active indicates that the location contained produced water, inactive sumps were empty, and the rest are unknown status. Data from CVRWQCB 2015 and Borkovich 2015a and 2015b (Appendix Chapter 2, 2.G).

	Status			
County	**Active**	**Inactive**	**Unknown**	**Total**
Kern	484	221	138	843
Fresno	31	16		47
Tulare	30			30
Santa Barbara	9	4		13
Kings	9			9
San Benito	1	3	1	5
Monterey	1	1		2
San Luis Obispo	1			1
Grand Total	**566**	**245**	**139**	**950**

To reduce access to sumps by animals, California regulations require that any pond containing oil or a mixture of oil and water must be covered with a net with no more than a two-inch mesh (California Code of Regulations Title 14 § 1770 on Oilfield Sumps). Ponds not containing oil are not subject to such a requirement. We used the reported locations of percolation pits gathered by the Central Valley Regional Water Quality Control Board to plot the locations of sumps in Google Earth and survey the pits for nets. We randomly selected 200 sumps to survey. Of these, 114 contained fluid at the time the aerial photograph for Google Earth was taken. Twenty-seven of the 114 pits in use (24%) were covered with nets. We could not determine whether unnetted pits had trace oil in the water or whether they all met the legal requirements to be unnetted. Nonetheless, other constituents besides oil could impact the health of organisms that come in contact with the sumps, particularly if the produced water contains traces of stimulation chemicals.

While there are at least 950 known sumps in eight counties, not all of these have necessarily received produced water from stimulated wells. As discussed in detail in section 2.5.3.3 of this volume, "Management of Produced Water," and 2.6.2.1, "Use of Unlined Pits for Produced Water Disposal," reports of disposal of wastewater specifically from stimulated wells to unlined pits was limited to Kern County and was associated with the Elk Hills, South Belridge, North Belridge, Lost Hills, and Buena Vista fields. Very few operators are discharging wastewater from stimulated wells to creeks or streams, with two stimulated wells reported to be discharging a total of 2,060 m^3 (2 acre-feet) of wastewater into surface water bodies during the first full month following stimulation.

As described in depth in section 2.6.2.9 of this volume, "Spills and Leaks," there are two databases maintained by the state on spills of oil and produced water, one by DOGGR and one by California Governor's Office of Emergency Services (OES). The OES database also documents chemical spills on oil fields. Neither dataset provides information, such as an American Petroleum Institute (API) number, that would allow a spill to be associated with a stimulated well. The databases also do not give precise identification nor concentrations of the chemical constituents of spilled substances, giving very general descriptions such as "produced water" or "acid" that do not allow evaluation of the ecological impacts. Between January 2009 and December 2014, a total of 575 produced water spills were reported to OES, or an average of about 99 spills annually. The majority (55%) of these spills occurred in Kern County, followed by Los Angeles (16%), Santa Barbara (13%), Ventura (6%), Orange (3%), Monterey (2%), and San Luis Obispo (1%), and Sutter (1%) counties. Nearly 18% of these spills impacted waterways. Chemical spills were also reported in California oil fields, including spills of chemicals typically used in well stimulation fluids, e.g., hydrochloric, hydrofluoric, and sulfuric acids. Between January 2009 and December 2014, a total of 31 chemical spills were reported to OES. Forty-two percent of these spills were in Kern County, followed by Los Angeles (16%), Sonoma (16%), and Lake (3%) counties. Chemical spills represent about 2% of all reported spills attributed to oil and gas development during that period. 10% of the chemical spills were reported to enter a waterway.

At present there is insufficient data available to determine the concentration and volume of the chemical constituents in wastewater intentionally and accidentally released to the environment. The impact to the environment will depend on a multitude of unknown factors including the volume and chemical content of the wastewater, how it is treated, where it is released, and transformations in the environment.

5.3.3.1.2. Discharges to the Ocean

Although ocean discharge from platforms in State waters (within 3 nautical miles of the coast) is prohibited, platforms operating in federal waters off California's coast are legally allowed to discharge treated produced water which may contain flowback containing stimulation chemicals to the ocean. Chapter 2 Section 2.5.3.3.2, "Wastewater from Offshore Oil and Gas Operations," describes the scope of the discharge and the regulations on its volume, composition, and monitoring. Accidental discharge of fluids to the ocean is also possible, although we are not aware of any data indicating that the rate of accidental spills, such as blowouts, differs for stimulated and unstimulated wells. As such, the main difference between a spill from a stimulated versus unstimulated well would be the potential presence of stimulation fluids. The potential impacts to the marine ecosystem of intentional and accidental discharge will be examined in-depth in the Volume III Offshore Case Study.

5.3.3.2. Ecotoxicology of Well Stimulation Fluids and Wastewater

Adverse impacts on wildlife and vegetation can result from exposure to chemicals in stimulation fluids and wastewater from stimulated wells. The data on the chemical content of these substances is discussed in depth in Vol II Chapter 2 Sections 2.4, "Characterization of Well Stimulation Fluids," and 2.5.4, "Wastewater Characteristics." In that chapter, environmental hazards of well stimulation additives and wastewater were evaluated in detail with respect to acute and chronic toxicity, bioaccumulation, and environmental persistence. In this section, we briefly revisit the topic with a focus on potential impacts to wildlife and vegetation if organisms are exposed to these fluids. However, our understanding of the long-term impacts of low-level exposure to these chemicals is limited, because much of the information on toxicity to organisms is collected in the laboratory using relatively high concentrations of individual chemicals. Impacts to organisms from a release of well stimulation and/or wastewater to the environment will depend on the actual concentration of chemicals and the reactions they undergo in the environment. In addition, standard toxicity tests are conducted on a limited suite of organisms that may not reflect the biology of California's native biota (see Vol II Chapter 2 Section 2.4.4.4, "Characterization by environmental toxicity," for more detail).

5.3.3.2.1. Stimulation Fluids

Exposure to chemicals used in well stimulation has been shown to adversely affect mammals, fish, invertebrates and algae in acute toxicity tests. Environmental toxicity

of stimulation fluids is discussed in depth in Volume II Chapter 2 Section 2.4.4.4, "Characterization by Environmental Toxicity" and Section 2.4.7, "Other Environmental Hazards of Well Stimulation Fluid Additives."

5.3.3.2.2. Inorganics in Wastewater

Wastewater from stimulated wells is made up of a mixture of stimulation fluids, formation fluids, and well clean-out fluids (see Chapter 2 Section 2.5.2, "Description of Wastewaters Generated by Well-Stimulation Operations)." Some inorganic chemicals in underlying rock formations that are brought to the surface through oil and gas production can be hazardous to wildlife and vegetation. Some geologic formations associated with well stimulation activity in California contain relatively high levels of trace elements and radionuclides (Piper et al., 1995; Presser et al., 2004). Inorganics mobilized by well stimulation may pose a risk to California wildlife and vegetation. Selenium enrichment is particularly problematic in the western San Joaquin Valley, including Kern County (Presser and Ohlendorf, 1987). Selenium exposure can cause developmental toxicity in birds and fish at environmentally relevant levels (Presser and Barnes, 1985). Several other trace elements (e.g., Cd, Cu, Ni, V) that are enriched in well stimulation areas are known to cause adverse effects in wildlife and vegetation at environmentally relevant levels (e.g., Eisler 1998; Larison et al., 2000; Rattner et al., 2006; Shahid et al., 2014). Formation water is also typically high in salt content; many plants and aquatic organisms in particular are highly sensitive to salt concentrations (Allen et al., 1975; Pezeshki et al., 1989; Ruso et al., 2007). Among the metals copper, selenium, titanium and vanadium are the most likely to accumulate (Love et al., 2013). Persistence, biodegradation, and bioaccumulation are discussed in more detail in Chapter 2 Section 2.4.7.1, "Environmental Persistence."

A major gap in knowledge of the ecotoxicology of stimulation fluids and associated wastewater is how the number of toxic and/or persistent compounds already used in well stimulation fluids might alter the toxicity and persistence of the chemical compounds in produced waters. The literature on possible additivity and synergistic interactions of persistent/toxic compounds is scarce and a proper risk assessment of chemical mixtures is currently hampered by the lack of data (Martins et al., 2009; Shen et al., 2006; Stelzer & Chan, 1999; Pellacani et al., 2012).

5.3.3.2.3. Hydrocarbons in Wastewater

Produced water generally contains a number of soluble hydrocarbons, along with metals and other compounds used in well treatment (Benko & Drewes, 2008; Clark & Veil, 2009). In California most information on produced water in the marine environment is from oil production facilities in the Santa Barbara Channel. Most of the toxicity of produced water is attributed to the water-soluble fractions of the hydrocarbons (Garman, et al., 1994). At a well blowout site in Kern County, Kaplan et al. (2009) found evidence that Heermann's kangaroo rats (*Dipodomys heermanni*) incorporated into their livers a set of chemicals, polycyclic hydrocarbons, that originated from crude oil.

5.3.3.3. Summary of Impacts of Discharges of Stimulation Fluids and Wastewater to Wildlife and Vegetation

When handled without accident, wastewater can be either reused or disposed of. One type of reuse involves re-injecting produced water into the formation to enhance oil recovery and counteract subsidence. Occasionally wastewater is used for irrigation or industrial purposes. Alternatively, wastewater may be disposed of in pits or injection wells, referred to as Class II wells in the USEPA's Underground Injection Control Program. A very small amount is disposed of by discharging it directly into the ocean. No matter how wastewater is reused or disposed of, there is the potential for spills and environmental releases of chemicals used in the well stimulation process. Laws and regulations seek to minimize the occurrence and consequences of environmental releases of inadequately treated fluids, however releases of chemicals to the environment can and do occur. Chapter 2 of this volume analyzed the potential effects of these releases by considering the toxicity of the most commonly used chemicals for well stimulation, and the chemicals used in the greatest mass. The evaluation considered toxicity of relatively high concentrations of the chemical, and therefore represents a worst possible scenario. In practice, the chemicals are often diluted or removed by treatment practices before fluids are released to the environment.

Our understanding of the impacts of discharges of stimulation fluids and wastewater to wildlife and vegetation is hampered by lack of data on multiple levels. Based on ecotoxicology data on stimulation fluids and wastewater, we can state that the discharge of stimulation fluids and wastewater from stimulated wells has the potential to harm wildlife and vegetation, but the actual magnitude of the impacts will depend on the frequency, location, volume, and chemical concentrations of discharges. We lack substantive data on the frequency of releases, the volumes and concentrations of discharges, and the long-term impacts on wildlife and vegetation once the fluids enter the environment. More is known about the potential indirect impacts of inorganics and hydrocarbons in formation waters and production fluids than the direct effect of stimulation fluids. Mammalian wildlife can be more susceptible to adverse effects of inorganics and hydrocarbons due to higher exposure levels than the human population. Increased data collection on potential releases of stimulation fluids and wastewater to the environment and refinement of the ecotoxicological analysis would lead to a better understanding of this risk.

5.3.4. Use of Water Can Harm Freshwater Ecosystems

Water is the main constituent of stimulation fluids, and water use to make stimulation fluids is a direct impact of well stimulation. Well stimulation can also in some situations enable production from reservoirs that also require enhanced oil recovery for effective production (EOR). Common forms EOR such as water flooding, steam flooding, and cyclic steaming require. Use of water for EOR enabled by hydraulic fracturing is an indirect impact of well stimulation. Competition for water with human uses is a major cause in the

alteration and decline of the state's aquatic ecosystems (Moyle and Leidy, 1992). Water use for well stimulation is discussed in detail in Chapter 2 Section 2.3, "Water Use for Well Stimulation in California." Water for well stimulation is a small fraction of freshwater used in the state. Chapter 2 reports that well stimulation in the state uses 850,000 to 1,200,000 m^3 (690–980 acre-feet) annually; this is about 0.01% (one ten-thousandth) of California's annual human water use. Even factoring in EOR enabled by well stimulation, the proportion of water use for both well stimulation and well stimulation – enabled EOR is 0.03% (three ten-thousandths) of annual human water use in the state. However, well stimulation is a highly geographically clustered activity, so it is important to consider water use in a regional context. Chapter 2 looks at water use for well stimulation and EOR enabled by well stimulation within planning areas. There are 56 planning areas in the state, ranging in size from 320 to 7,500 square miles, with an average size of 2,600 square miles. The planning area with the largest proportion of its water used by well stimulation and EOR enabled by well stimulation is the Semitropic Planning Area in the western portion of Kern county. In the Semitropic, .19% of the annual water use, or 2,900,000 m^3, is for well stimulation and EOR enabled by well stimulation. Thus, even in the region where most of the well stimulation in the state occurs, it represents a small proportion of total water use.

The statistics on water use for well stimulation on a state-wide and regional scale indicate that well stimulation represents a small percentage of water diverted from large sources. Of the 495 well stimulation completion reports filed with DOGGR between January 1 and December 10, 2014, all but two were for operations in Kern County. Most of the Kern County operations (397, or 83%) used water from the Belridge Water Storage District, which sources water from the State Water Project. The State Water Project delivers about 470 million m^3 (2.3 million acre-feet) in average years, which dwarfs the amount of water used for well stimulation; as a result, a very small proportion of the impact to ecosystems by the State Water System can be attributed to withdrawals for well stimulation.

The available data on water use for stimulation does not allow us to do is to determine whether water diversions for well stimulation cause very small-scale, local impacts on surface waterways. The main pathway for water use to impact the health of an ecosystem is if water use is a large proportion of streamflow for a surface waterway, or if groundwater is drawn down locally so that it substantially decreases baseflow to a stream. While water use for well stimulation is of a small enough volume that it is unlikely to have a substantial impact on large bodies of water, it is conceivable that an operator could divert a large proportion of a small waterway or locally draw down groundwater enough to affect small bodies of surface water. In order to understand very local impacts such as these, data on the source of well stimulation water would need to be reported on a finer spatial scale than it is at present. In well stimulation disclosures, operators report the source of water by category such as irrigation districts (68%), produced water (13%), operators' own wells (13%), a nearby municipal water supplier (4%), or a private landowner (1%). This level of reporting does not allow us to establish if, for example, a proportionately large amount of water is being withdrawn from the groundwater by private wells in one small area, or diverted from a small surface waterway.

5.3.5. Noise and Light Pollution Can Alter Animal Behavior

Oil and gas operations are sources of anthropogenic noise caused by equipment and night-time lighting. Some noise is generated by the equipment used specifically for well stimulation, chiefly the hydraulic fracturing pumps, and would be considered an indirect impact. Noise is also generated at other stages of process such as site preparation, drilling, and production and would be considered an indirect result of well stimulation. Night-time lighting for production enabled by stimulation would be an indirect impact. Well stimulation operations typically last on the order of hours (King, 2012), so the duration of noise and light directly caused by well stimulation is brief compared to the months to years of noise and light associated with ensuing production.

Noise and artificial night lighting have been shown to effect the communication, foraging, competition, and reproduction of organisms. Sound is an important sensory tool for animals and noise pollution from oil and gas production has been shown to alter their behavior, distribution, and reproductive rates (Blickley et al., 2012a and b; Francis et al., 2012). Noise is generated at all stages of the oil and gas production process, from construction of the well, stimulation, and production, until the well is abandoned. We could find only one reported measurement of noise specifically during hydraulic fracturing in California. Noise levels of 68.9 and 68.4 decibels (dBA) were measured 1.8 m (5 ft) above the ground 33m (100 ft) and 66 m (200 ft) away from a high-volume hydraulic fracturing operation in the Inglewood Field (Cardno ENTRIX, 2012). These levels are substantially lower than those found to disturb wildlife and ecosystem processes in Blickley et al. (2012a and b) and Francis et al. (2012). Observational data collected in the Elk Hills region of western Kern County between 1980 and 2000 suggested that the San Joaquin kit fox and other wildlife appeared to have habituated and acclimated to the regimen of noise, ground vibrations, and human disturbances associated with an active oil field (O'Farrell et al., 1986).

Ecological light pollution is a specific term describing chronically increased illumination and temporary unexpected fluctuations in lighting (Longcore and Rich, 2004). Sources of ecological light pollution include lighted buildings, streetlights, security lights, vehicle lights, flares on off-shore oil platforms, and lights on well pads. Light pollution has been shown to extend diurnal or crepuscular foraging behaviors (Hill, 1990; Schwartz and Henderson, 1991), reduced nocturnal foraging in desert rodents (Kotler, 1984), disorient organisms who hatch at night such as sea turtle hatchlings (Salmon, 2003; Witherington, 1997) and disorient nocturnal animals such as birds (Ogden, 1996) and frogs (Buchanan, 1993) leading to mortality or predation. Many studies have also noted changes of breeding and migration behaviors (Rydell, 1992; Eisenbeis, 2006; Stone et al., 2009; Titulaer et al., 2012; Bergen and Abs, 1997). Ecological light pollution can also disrupt plant by distorting their natural day-night cycle (Montevecchi et al., 2006). It is considered an important force behind the loss of light-sensitive species and the decline of nocturnal pollinators such as moths and bats (Potts et al., 2010) and can change the composition of whole communities (Davies et al., 2012).

There are no specific studies on the effect of artificial lighting on wildlife on or around well pads, however, some states like Maryland have implemented best management practices for oil and gas development to mitigate any potential effects. These include using only night lighting when necessary, directed all light downward, and using low pressure sodium light sources when possible (Maryland Department of the Environment and Maryland Department of Natural Resources, 2014).

5.3.6. Vehicle Traffic Can Cause Plant and Animal Mortality

Vehicles impact natural habitats by striking and killing animals; vehicles traveling off-road can cause plant mortality and compact the soil. The proppant, and occasionally water, required for well stimulation is transported via trucks; vehicles are also an integral piece of equipment in all other stages of oil and gas production. Road mortality is noted as a major factor affecting the conservation status of two state and federally listed species in California known to occur on the oil fields of the San Joaquin Valley: the San Joaquin kit fox and the blunt-nosed leopard lizard (Williams et al., 1998). Vehicle traffic is inherent in most stages of the oil and gas production process, including, but not limited to stimulation; therefore it is both a direct and indirect impact.

Road mortality on oil fields has specifically been studied in the San Joaquin kit fox. In one study at the Elk Hills Oil Field, the proportion of San Joaquin kit fox deaths due to road accidents was four times greater in developed areas versus in undisturbed areas (O'Farrell et al., 1986). A later study at the same field found vehicle-related mortality rates for endangered San Joaquin kit foxes were approximately double in oil-developed areas versus non-developed areas, although overall rates were considered low (20 of 225 deaths during 1980-1995; (Cypher et al., 2000). Similarly, (Spiegel and Disney, 1996) found that none of 29 foxes found dead during 1989-1993 in the highly developed Midway-Sunset and McKittrick-Cymric oilfields had been killed by vehicles. Restrictions on speed limits and off-road driving that are imposed in many oil fields as a measure to mitigate vehicle strikes may explain the low mortality rates.

5.3.7. Ingestion of Litter Can Cause Condor Mortality

As with many sites of human activity, oil and gas pads can become deposits for litter. While there may be marginally more litter as a result of the process of preparing a site for production taking slightly longer and requiring more staff when stimulation is involved, litter is presumably mainly an indirect impact that is associated with all stages of the hydrocarbon production process, not just well stimulation.

Critical habitat for the California Condor overlaps with the Sespe Oil Field in the Los Padres National Forest, and the Sespe Condor Sanctuary is adjacent to the oil field of the same name. U.S. Forest Service guidelines that well pads be maintained free of debris. Nonetheless, oil operations are nonetheless potential sources of microtrash that can cause mortality in condors (Mee et al., 2007a and b; USFWS, 2005). Microtrash consists of

any man-made item that is sufficiently small to be ingested by a condor, up to about 4 cm in diameter. Items found in condors have included nuts, bolts, washers, copper wire, plastic, bottle caps, glass, and ammunition cartridges (Mee et al., 2007a and b; Walters et al., 2010). For reasons that are unclear, adults will collect such items and feed them to nestlings (Mee et al., 2007a and b; Rideout et al., 2012). Of 18 nestlings for which cause of death could be determined, 8 (44%) deaths were attributable to microtrash ingestion (USFWS, 2013). The national forest, the U.S. Bureau of Land Management (BLM) (which administers the mineral rights in the forest), and the USFWS all have imposed measures to minimize or eliminate the presence of microtrash (USFWS, 2005).

5.3.8. Potential Future Impacts to Wildlife and Vegetation

In this report we predict that the main focus for hydraulic fracturing in the state will continue to be in and around the areas where it is already used, principally the southwestern San Joaquin Basin (Volume I Chapter 4). The possibility of a sudden development of new areas with hydraulic fracturing-enabled production hinges largely on the possibility of developing Monterey source rock, which is a highly uncertain possibility at this stage. Here we briefly summarize what we know and the data gaps about potential future well stimulation impacts to wildlife and vegetation and refer the readers to the relevant sections of other volumes for more detail.

- Hydraulic fracturing will likely continue to be an important part of oil and gas production in California. In this report we predict that it will continue in and around the fields where it is already routinely used, principally in the San Joaquin Valley (Volume I Chapter 4, Volume II Chapter 5). However, we cannot predict the future location and density of hydraulically fractured wells. As a result we refrain from making detailed forecasts about future habitat loss and fragmentation caused by hydraulic fracturing.

- The degree to which new development will affect habitat loss and fragmentation will depend on whether future development is “infill” (an increased density of already-developed areas) or expansion (growth in undeveloped areas), and the degree to which wells and other infrastructure are clustered or evenly distributed across the landscape. Volume III Chapter 5 examines production as a function of well density in one pool of the Lost Hills oil field and concludes that production increases linearly with well density, suggesting that operators will continue to drill new wells in already-developed areas to increase total yields. The lease with the highest yield in the Cahn pool has a well density of approximately 200 wells per km^2; we would predict that, as long as the activity remains profitable, the remainder of this pool will reach similar densities. A study in another San Joaquin oil field found that native species disappeared at well densities of about 100 wells per km^2 (Fieler and Cypher, 2011). We do not know if all hydraulically fractured pools show a similar linear relationship between yield and well density, but the study of the Cahn pool suggests a possible way to examine this question on a pool-by-pool basis in future research.

- We do not know the limit of the surface footprint of pools requiring hydraulic fracturing. Volume III, Chapter 5 examines two pools in detail, the Cahn Pool at Lost Hills field and the Pyramid Hill-Vedder pool in Mount Poso field, and notes that there is a mix of curved and linear borders of wells producing from these pools. The linear borders suggest that development was limited by a legal boundary (such as a lease) and that the geological resource extends further. This suggests that there are untapped resources just beyond the reach of existing wells that can be developed in the future with the application of hydraulic fracturing.

- While we identify potential pathways for impacts of well stimulation to wildlife and vegetation besides habitat loss and fragmentation in this chapter, the available information is insufficient to quantify past or future impacts to populations. For example, while we know that the release of stimulation chemicals is a possible impact, we do not know to what degree it occurs nor whether it causes declines in population sizes. Without adequate information on past and present impacts, we cannot hope to predict the future impacts.

- It is possible that hydraulic fracturing could open large new areas for development if operators learned how to effectively develop Monterey source rock, although these areas would still be in the general vicinity (within 20 kilometers) of existing oil fields in the six largest oil-producing basins in the state (Volume III Chapter 3). At present there is no reliable resource assessment of Monterey source rock. Based on the documented challenges in developing Monterey source rock, economic production of Monterey source rock appears to be a remote possibility at present, and one which would require technological innovations that may change the profile of impacts from oil and gas production (such as greater reliance on clustered, horizontal wells). Because of these many uncertainties, we did not perform a detailed prediction of future well density in the Monterey source rock footprint, although we did examine the biological resources present in the area to consider the environmental context in which the development could occur. The footprint of Monterey source rock is in the San Joaquin, Ventura, Los Angeles, Salinas, Santa Maria, and Cuyama basins. Within the footprint, about 60% of the area is used intensively by people (i.e. for cities, agriculture, or industry), and about 40% is open space (grass and shrublands, forest, and open water). The footprint of potential Monterey source rock underlies the area of the southwestern San Joaquin identified as highly sensitive in this chapter.

5.4. Laws and Regulations Governing Impacts to Wildlife and Vegetation from Oil and Gas Production

While the preceding has outlined the major potential hazards to wildlife and vegetation, the degree to which these hazards actually impact wildlife and vegetation is mitigated to some extent by the numerous federal and state laws governing how human activities such as well stimulation must be carried out to minimize impacts on wildlife and vegetation.

For example, the National Environmental Policy Act (NEPA), the Federal Endangered Species Act (ESA), the Migratory Bird Treaty Act, the California Endangered Species Act (CESA), California Fully Protected Designations, and the California Environmental Quality Act (CEQA) are directed at protecting the natural environment. In this section, we briefly review regulations applicable in California in order to describe the regulatory system as it pertains to impacts to wildlife and vegetation of oil and gas production and well-stimulation-enabled oil and gas production.

A detailed description of the regulatory setting for biological resources in California is given in the SB4 Draft Environmental Impact Report (Aspen Environmental Group, 2015a and 2015b). However, the pertinent laws do not consistently establish practices that all California oil and gas producers must enact to reduce their impacts on wildlife and vegetation. The relevant laws are brought to bear differently depending on which agencies have jurisdiction over the project and site-specific circumstances. This results in a patchwork of agreements that are not necessarily consistent with one another on a statewide or even regional scale, and that are not compiled in one central repository that is publicly available, but rather exist in the records of a multitude of federal, state, and local agencies, and the private entities who entered into the agreements. For example, Occidental Petroleum and the California Department of Fish and Game[6] entered into a memorandum of understanding and take authorization governing activities at Elk Hills oil field (California Department of Fish and Game, 1997). This document does not apply to any of the other fields in the state.

The process by which environmental regulations are applied to minimize impacts to wildlife and vegetation varies depending upon the landowner and the mineral rights owner at a given location. Not uncommonly, a "split estate" situation exists whereby the owner (s) of the land and the owner (s) of the mineral rights beneath that land are different. If the land or mineral rights are federally owned, then the process is more consistent. In these situations, the federal agency that owns the surface and/or mineral estate must authorize any oil and gas development projects and grant permits. These actions necessitate formal review of the proposed project under NEPA. The federal action agency, often with a project description and site-specific information provided by the project proponent, prepares an Environmental Assessment or Environmental Impact Statement under NEPA to analyze the effects of the project. Appropriate terms and conditions are attached to the federal authorization to avoid or mitigate project effects on natural resources.

Ideally, this document describes how the project will comply with all applicable environmental laws. Also, the federal agency is responsible for ensuring that the project proponent complies with all applicable laws and regulations (see Aspen Environmental Group 2015a and b for a list of applicable laws and regulations).

6. Now known as the California Department of Fish and Wildlife.

If the land and mineral rights are privately owned, then the process depends upon the nature of the proposed project. If the project is to drill a new well, the well must be permitted by DOGGR. Before DOGGR can issue a permit, the project is required to be subjected to review under CEQA. The project proponent prepares an Environmental Impact Report, and this is the document that is subject to review. Ideally, this document describes how the project will comply with all applicable environmental laws. If the project is something other than a new well (e.g., construction of infrastructure such as pipelines, facilities, etc.), then the responsible agency usually is a county or local municipality. The requirements and process are then very variable with some agencies providing little to no requirements or oversight with regards to environmental regulations, and others imposing rigorous requirements and oversight. Even when agency oversight is minimal or non-existent, project proponents still are required to comply with all laws and regulations, but such compliance tends to be variable.

Given the patchwork of regulatory agreements pertaining to oil and gas activities throughout the state and the lack of any centralized collection for such agreements, it is not possible for us to fully evaluate the regulations that the various oil and gas operators may or may not be operating under, nor evaluate the degree to which these agreements are consistent or complementary with one another. We emphasize that the lack of consistency in the application of regulatory requirements is in no way unique to oil and gas operations, but instead is common to all activities evaluated under the acts listed at the beginning of this section. The requirements tend to vary among habitats, species, agency staff conducting the evaluations, and precedents established among offices within agencies. Finally, requirements for a given oil and gas project may vary depending upon whether the project was initiated before or after a given regulatory act was passed and implemented.

5.5. Measures to Mitigate Oil Field Impacts on Terrestrial Species and Their Habitats

The potential hazards to wildlife and vegetation posed by well stimulation and the production it enables can be reduced through application of the appropriate mitigation measures. A variety of measures are frequently required in oil fields in California to avoid or mitigate impacts to terrestrial species and their habitats resulting from oil and gas extraction activities. To our knowledge, no mitigation measures for the protection of terrestrial species and their habitats are specific to well-stimulation activities, but apply to oil and gas production activities that can be enabled by well stimulation such as construction of well pads, roads, facilities, and pipelines; maintenance and operations; and seismic surveys.

The list of measures presented in this section is largely derived from examples in the San Joaquin Valley, where oil field activity is extensive and where sensitive biological resources are abundant (see Introduction, Section 5.2, for synopsis of San Joaquin Valley biological values). Measures implemented in other regions probably are similar with nuances specific to the species and habitats in those regions.

Below, we list and describe commonly implemented mitigation measures in oil fields. This list was compiled from documents that addressed oil and gas production in large oil fields or over large regions. The primary documents were U.S. BLM, 2010; U.S. DOE, 1991; 2001; US DOI, 2012; USFWS, 2001. The documents used in this compilation addressed large, extensive oil and gas production operations conducted over multiple years. All of the information presented below was distilled from the sources above unless otherwise cited. The measures are grouped into broad categories based on their intended purpose. Here we focus principally on impacts to the terrestrial environment; the alternative and best practices given in Volume II, Chapter 2 focus on strategies for reducing risks to water supply and quantity that can impact the aquatic environment.

5.5.1. Habitat Disturbance Mitigation

5.5.1.1. Compensatory habitat

In an effort to compensate for habitat destruction resulting from oil field activities, project proponents commonly are required to permanently conserve undisturbed habitat elsewhere. Such habitat is referred to as "compensatory habitat." This requirement can be satisfied by project proponents in various ways including using lands they already own, purchasing lands, and purchasing credits in an approved habitat mitigation bank. For lands owned or purchased, the project proponent can retain and manage the lands, or transfer them to a natural resources agency (e.g., CDFW) or an approved conservation organization (e.g., Center for Natural Lands Management). The lands must be protected in perpetuity and managed appropriately. Agency-approved management plans typically are required for lands retained by project proponents, and endowment funds for management must be provided along with lands transferred to another agency or organization.

This approach to mitigation uses what are generally referred to as "environmental offsets," and has become a common form of environmental regulation in the United States and Europe. The goal of offsets is to counteract the impact of development to achieve a net neutral or beneficial outcome. For example, beginning in the 1970s, most states adopted a "no net loss" policy for wetlands. Rather than banning all development in wetland areas, developers were given the option of compensating for wetland loss by creating new wetlands elsewhere on an acre-for-acre basis. The mitigation approach is not without its detractors, however; see e.g. McKenney (2005), Race and Fonseca (1996).

For California oil and gas projects, the ratio of compensatory land to altered land is variable. In the San Joaquin Valley, a common ratio is 3:1, meaning three units of compensatory habitat for every one unit of habitat disturbed. For "temporary" habitat disturbances (usually defined as disturbances lasting less than two years), the ratio is 1.1:1. Examples of temporary disturbances include the installation of buried pipelines and equipment staging areas. In such situations, the disturbed area is allowed to revegetate through natural or active habitat restoration, and then is again available for use by species. Other ratios have been required, including 4:1 in cases where protected lands are disturbed (USFWS, 2001). (Many lands in the San Joaquin Valley are "split estates" in

which one party owns the surface of the land and another party owns the mineral rights underlying the land. In such situations, access to the minerals must be granted. Thus, mineral extraction activities are not uncommon on protected lands.) A ratio of 6:1 was required for any projects that disturbed habitat for federally endangered Kern Mallow (*Eremalke kernensis*; USFWS, 2001). In the case of an oil field waste-processing facility constructed in highly sensitive habitat used by multiple listed species in Kern County, the required ratio was 19:1 (D. Mitchell, Diane Mitchell Environmental Consulting, personal communication).

Compensatory habitat is typically "in kind;" that is, the habitat must be of equal or higher value than the habitat that was disturbed. Furthermore, listed species present on the disturbed habitat also must be present on the compensatory habitat.

5.5.1.2. Disturbance minimization

Measures commonly are implemented to reduce the amount of habitat disturbed by oil-field activities. Some of the measures are implemented in the planning phase of a project (e.g., planning to drill multiple wells from a single pad). Other measures constitute best management practices implemented during the construction or operations phases.

- Use existing roads to the extent possible.
- Use previously disturbed areas to the extent possible.
- Try to aggregate facilities to the extent possible.
- Drill multiple wells from a single pad by using directional and horizontal drilling.
- Route pipelines along existing roads whenever possible.
- Elevate pipelines to minimize surface disturbance and allow animals to freely move under the pipeline.
- If off-road travel is necessary and permitted (e.g., seismic surveys), use all-terrain vehicles (ATVs) instead of full-sized vehicles when possible for cross-country travel, as ATVs are smaller and lighter and therefore cause less damage when driven across habitat.

In some situations, the total habitat disturbance permitted in a given area is restricted. Lands administered by the U.S. BLM in the southern San Joaquin Valley have been categorized based on the suitability of the lands for listed species. In "Red Zones," which are within identified reserve areas, surface disturbance from oil and gas extraction activities may not exceed 10%. In "Green Zones," which are identified as dispersal corridors between reserve areas, surface disturbance cannot exceed 25% (USFWS, 2001). This policy takes into account cumulative impacts from all projects on BLM land in the region.

5.5.1.3. Habitat degradation mitigation

Measures commonly are implemented to reduce habitat degradation. These measures are different from disturbance minimization measures in that they are intended to avoid or mitigate transient or accidental impacts that can degrade habitat quality.

- Prohibit off-road travel. Vehicles are restricted to use of existing roads.

- Contain and remediate fluid spills. Various types of fluids are used or produced in oil fields. Many of these fluids are highly toxic, but even clean water in inappropriate situations can cause flooding of burrows, drowning of individuals, and soil erosion. Control strategies can include building berms around facilities that hold fluids. If spills do occur in habitat, then clean up, removal of contaminated soils, and restoration may be required.

- Prevent and suppress fires. Fires can significantly degrade habitat quality, particularly in regions like the San Joaquin Valley where vegetation communities are not fire-adapted. Thus, oil field operators may implement a variety of measures to prevent fires, including use of spark arrestors on equipment, prohibiting open flames, restricting smoking at field sites, equipping all vehicles with fire extinguishers, and staging fire suppression equipment at field work sites.

- Prohibiting or restricting public access. Access to oil fields by the general public may be prohibited or at least limited. Access by the public can potentially result in environmental impacts, such as off-road vehicle use, shooting of animals, trampling of sensitive plant populations, wild fires, and trash dumping.

5.5.2. Avoidance of Direct Take

Measures commonly are implemented in oil fields to avoid the “taking” of listed species. According to the ESA and CESA, “taking” can include direct mortality, injury, harassment, or other actions that may adversely affect individuals of a listed species. This list was compiled from documents that addressed oil and gas production in large oil fields or over large regions. The primary documents were U.S. BLM, 2010; U.S. DOE, 1991; 2001; US DOI, 2012; USFWS, 2001.

- Conduct surveys to determine whether listed or sensitive species are present on or near sites where habitat will be impacted or where activities potentially put individuals at risk.

- Avoid to the extent practicable any sensitive habitat areas or biological features important to listed or sensitive species. Sensitive habitat areas can include vernal pools, riparian areas, wetlands, and rare plant locations. Important biological features can include dens, burrows, and roosting sites. Avoidance commonly is achieved through the establishment of exclusion zones that are closed to entry by humans and vehicles.

- Exclude, remove, or relocate individuals that cannot be avoided. If individuals or features cannot be avoided, then measures are usually required to remove them to avoid injury or death of individuals.

- Use signage to protect sensitive areas. Permanent signage sometimes is used to indicate sensitive habitat areas or important biological features and exclude entry by humans.

- Use fencing to exclude animal entry into dangerous areas. Fencing is sometimes used around project sites to exclude entry by rare animals. Typically, this strategy is applied to relatively small sites (e.g., well pads) that can be effectively fenced and that are not so extensive (e.g., long, linear projects) that the fencing would severely inhibit animal movements through the area. Occasionally, more extensive (e.g., long, linear projects) are fenced in segments so as to permit animal movements through an area. Examples of species commonly excluded with fencing include blunt-nosed leopard lizards (*Gambelia sila*), kangaroo rats (*Dipodomys spp.*), and California tiger salamanders (*Ambystoma californiense*).

- Install fencing and netting around and over sumps to exclude entry by animals. Sumps are commonly constructed to contain fluids produced in oil fields, in particular produced water that is pumped from wells along with oil and gas. Such water can include a variety of chemicals potentially harmful to animals. Animals can be attracted to sumps filled with produced water mistaking them for a source of drinking water or wetland habitat. Fencing and netting is placed around and over these sumps to prevent animals from accessing the water in which they could drown, or if ingested or absorbed, could cause injury or death.

- Cap all pipes to prevent entry by animals. Pipes are used in abundance in oil fields for drilling wells, constructing pipelines, and other purposes. Animals occasionally seek shelter in pipes, and then can be harmed or killed if they become entrapped in the pipe or the pipe is moved. Capping the ends of pipes prevents use by animals.

- Prevent animal entrapment in open trenches and pits. Trenches and pits are commonly dug in oil fields for a variety of purposes. Strategies to prevent animal entrapment include (1) covering them when work is not being performed, (2) monitoring, usually at the beginning and end of the work day, and removal of any animals, (3) reducing side slopes to 45 degrees or less, and (4) building ramps to allow any trapped animals to escape.

- Limit vehicle speeds. To reduce the potential for animals to be struck by vehicles, speed limits are commonly imposed in oil fields. In areas with listed or sensitive species, limits are typically no more than 25 mph and sometimes as low as 5 mph. Lower speed limits may be required at night when animals are active.

- Remove all trash and food that might attract animals to work sites. Typically at the end of the work day, all trash and food is removed from the site so as not to attract animals.

- Prohibit dogs or other pets. Domestic animals, particularly dogs, potentially could pursue, capture, and kill wildlife species. Even just the presence of dogs potentially could alter wildlife behavior in a detrimental manner. Domestic animals also could carry and introduce diseases into local wildlife populations.

- Prohibit firearms. This restriction is imposed to prevent the shooting of wildlife.

- Restrict pesticide use. Use of pesticides (e.g., rodenticides, insecticides, herbicides, etc.) may be prohibited or strictly regulated to avoid poisoning of wildlife and plants.

- Mitigation measures for rare plants. In areas where rare plant populations are known to occur, mitigation measures specifically for plants may be required. These measures include (1) complete avoidance of oil field activities, where possible, (2) limiting activities in plant populations to the period between seed set and germination, (3) collecting seeds and redistributing them in nearby undisturbed areas, (4) collecting and storing top soil, and then redistributing it in disturbed areas or back on the original site if the disturbance is temporary, and (5) prohibiting the use of herbicides in or near plant populations.

- Use of biological monitors. Biological monitors may be required to be present when work is being conducted. This is a common requirement in areas where listed species are known to be present. Biological monitors must be qualified biologists (i.e., trained to recognize species of interest and knowledgeable of applicable laws and regulations as well as appropriate responses to the appearance of species on work sites or non-compliance by workers). Monitors ensure that exclusion zones are avoided by workers, monitor activity by sensitive animals, monitor worker compliance, participate in worker education and awareness programs, and prepare compliance reports. Monitors commonly have the authority to halt work in situations such as (1) the appearance of a listed species on site, (2) death or injury of a listed species, or (3) non-compliance by workers.

5.5.3. Environmental Restoration

Restoration involves environmental remediation and recovery of ecological functions on sites where habitat has been disturbed. DOGGR provides some guidance and requirements (California Code of Regulations Title 14 § 1776 on Well Site and Lease Restoration). In essence, upon abandonment, wells must be plugged and all structures and materials on the surface must be removed. Any toxic or hazardous materials must be cleaned up. Any excavations must be filled and compacted, and any unstable slopes must be mitigated. Finally, the site should be "returned to as near a natural state as practicable."

Otherwise, requirements for restoration are inconsistent and range widely from none to extensive. On U.S. BLM lands in the southern San Joaquin Valley, intensive restoration is required and detailed protocols and procedures are provided to project proponents (USFWS, 2001). In other instances, project proponents are asked to prepare a restoration plan and submit it for agency approval (Padre Associates, 2014). The purpose of restoration efforts is to try to reestablish sufficient ecological function on previously disturbed lands such that they can again be used by local native species. Restoration usually is conducted whenever a disturbed area (e.g., road, well pad, facility site, pipeline) is no longer needed for oil and gas production activities.

Elements of restoration could include the following:

- Removal of all anthropogenic materials.
- Removal of any contaminated soil.
- Ripping/disking the site to reduce soil compaction.
- Earthwork to restore natural contours of a site.
- Seeding with native plants (seed mixes vary immensely but usually include one or more shrub species).
- Application of sterile straw or other cover material to inhibit erosion.
- Monitoring restoration success. A typical performance measure is to restore vegetative cover on a disturbed site such that it is equal to at least 70% of the cover on nearby undisturbed sites.

5.5.4. Employee Training

A common requirement for oil and gas production operations is to provide environmental training for employees. Such training generally is required of any individual that works on a given project, even if employee responsibilities do not include field work. Employee education and awareness programs commonly include information on:

- How to recognize listed and sensitive species.
- How to recognize sensitive habitats.
- Mandatory mitigation measures and their implementation.
- Applicable laws and regulations, and consequences that could result from non-compliance.

5.5.5. Regional Species-Specific Measures

Most of the measures described above are relatively general and therefore widely applied. In addition to these general measures, there may be measures required that are specific to local listed or sensitive species. Appendix 5.A gives specific measures that have been required in oil fields occurring within the range of California condors (*Gymnogyps californianus*), Arroyo toads (*Bufo californicus*), red-legged frogs (*Rana aurora draytonii*), and fairy shrimp (Castle Peak Resources, 2011; USFWS, 2009; 2005).

5.5.6. Efficacy of Mitigation Measures

As detailed above, numerous measures have been implemented in oil fields to mitigate impacts to terrestrial species and their habitats from oil and gas production activities. However, rarely has the efficacy of any of the measures been assessed. In general, most of the measures have not been subject to systematic studies quantifying the contribution of the measures to the conservation of biological resources. However, a small number of assessments have been conducted, and these are summarized below.

5.5.6.1. Use of Barriers to Exclude Blunt-Nosed Leopard Lizards

Germano et al. (1993) evaluated the use of barriers to exclude endangered blunt-nosed leopard lizards from a 2-km pipeline trench and associated right-of-way. Prior to erecting barriers, lizards were getting trapped in the trench and were observed along the right-of-way used by construction vehicles. They used strips of aluminum flashing and plastic erosion cloth, and both materials effectively excluded lizards from the construction area, although the flashing was cheaper and less likely to collapse.

5.5.6.2. Use of Topsoil Salvage to Conserve Hoover's Wooly-Star

Hinshaw et al. (1998) investigated the salvage of topsoil to establish threatened Hoover's wooly-star (*Eriastrum hooveri*) on disturbed sites. Topsoil laden with Hoover's wooly-star seeds was collected from within population areas and redistributed on disturbed sites in areas with and without the species. Within populations, reestablishment rates were similar between plot that received topsoil and control plots. In areas where the species was not present, Hoover's wooly-star was successfully established in low densities.

5.5.6.3. Habitat Restoration for San Joaquin Valley Listed Species

Hinshaw et al. (2000) assessed sites on Naval Petroleum Reserve No. 1 (Elk Hills Oil Field) on which habitat reclamation had been conducted. Reclamation methods had included site preparation and seeding with annual plants and shrubs. They examined 996 sites five years and 10 years post-reclamation. After five years, 47.2% of the sites met the success criterion of vegetative cover equal to or exceeding 70% of the cover on reference or adjacent undisturbed sites. After 10 years, 77.4% of the sites met the criterion. However, they cited unpublished data from a study in which a subset of the sites had been compared to sites on which no reclamation was conducted but instead were allowed to revegetate naturally. Revegetation occurred at least as rapidly on non-reclaimed sites as on reclaimed sites. Furthermore, reclaimed sites commonly had shrub densities exceeding those on reference sites, and these dense shrubs provided optimal cover for predators of endangered San Joaquin kit foxes, possibly to the detriment of the kit fox. Reclamation costs averaged $11,827 per successfully revegetated hectare. The authors concluded that at least in the southern San Joaquin Valley, habitat restoration could be achieved by simply preventing additional disturbance of sites and allowing them to revegetate naturally, and any conservation funding might be better spent on acquiring additional undisturbed habitat versus reclaiming disturbed habitat.

5.6. Assessment of Data Quality and Data Gaps

- For all the potential impacts of well stimulation to wildlife and vegetation identified in, there are major data gaps in understanding the actual extent of the impacts. Of all the impacts, the most data were available to quantify habitat loss caused by hydraulic-fracturing-enabled-production; even here we were hampered by the lack of comprehensive historical data on the frequency and location of hydraulic fracturing. For all other impacts the data gaps were even larger. For introduction of invasive species, releases of harmful fluids to the environment, water use, litter, noise, light and traffic, there are insufficient data on how well stimulation alters the environment and if and how wildlife and vegetation in California are actually affected.

- While we have data that allows us to make a reasonable estimate of habitat loss caused by hydraulic fracturing enabled production, we have very little information on other important pathways of impacts of well stimulation to wildlife and vegetation such as the kinds and quantities of hydraulic fracturing chemicals that enter the environment; the degree to which local streams could be impacted by water withdrawals for stimulation; the noise caused by well stimulation; litter, traffic, noise and light generated at well stimulation sites.

- While we know that an increasing density of wells causes loss and fragmentation of habitat, we have a very limited understanding of how this in turn affects the local organisms that inhabit the area. How does the increasing density of oil wells affect local population sizes, behavior, habitat selection, and migratory patterns of organisms? What are the mechanisms of any impacts to wildlife and vegetation – loss of habitat, water use, water contamination, noise, light, traffic, litter, or other causes?

- Most of the literature on ecological impacts of oil and gas production in California was conducted in order to comply with regulatory requirements and thus tends to focus on threatened and endangered species protected under the United States and California Endangered Species Acts. There has been relatively little work on species that are not listed as endangered or threatened, or on more general ecosystem properties such as biodiversity.

- To date, there has been little evaluation of the effectiveness of mitigation measures. Rigorous evaluation of the various, commonly prescribed mitigation measures would allow regulators to identify and require only those methods with proven value. The contribution of mitigation measures to overall conservation efforts is unknown. Even assuming that all mitigation measures are effective in achieving their intended purpose (e.g., avoiding take, preventing additional habitat disturbance, restoring habitat), there has been no assessment of whether such measures contribute significantly to the conservation of species.

- Habitat restoration of abandoned oil and gas well sites can be an important tool for conservation, but the very limited studies available in the San Joaquin Valley found that neither passive revegetation nor active restoration efforts restored sites to their pre-disturbance value for native species. More experimentation in this arena would tell us if restoration is possible, and if so, what approaches are effective.

- Cumulative effects analyses, which look at the additive impacts of multiple projects over regional scales and time scales of years or longer, are inadequate. Environmental impact reviews are conducted for most oil and gas production activities and these reviews typically include a cumulative effects analysis, but most are conducted on a project-specific or site-specific basis with little consideration of the larger regional landscape. No comprehensive analysis has been conducted on cumulative environmental effects. Such analyses are critical, particularly in regions like the San Joaquin Valley where profound habitat loss from a variety of sources including oil and gas production may have already precluded the recovery of some listed species.

5.7. Findings

- While some portions of oil and gas fields are dedicated nearly exclusively to hydrocarbon production, in other areas oil and gas production is interspersed with human development, agriculture, and natural habitat.

- There are a number of places in the state where valuable natural habitat is interspersed or adjacent to well-stimulation-enabled production. In those areas where hydraulic fracturing-enabled production occurs in a landscape of natural habitat, the additional production causes habitat loss and fragmentation. The counties with the greatest amount of habitat loss and fragmentation attributable to well-stimulation enabled production were (with hectares of altered habitat in parenthesis): Kern (13,400), and Ventura (5,000).

- Compared to the total area of natural habitat in the state, the amount altered by hydraulic-fracturing-enabled-production is modest, less than one-tenth of a percent of the total area of natural habitat. However, the effects are highly localized and have disproportionate effects in a few areas and for a few habitat types. For valley saltbush scrub, 6% of its statewide extent was impacted by hydraulic-fracturing-enabled-production, and 2% for Venturan coastal sage scrub.

- The natural communities most disturbed by well-stimulation-enabled production were valley saltbush scrub and non-native grassland (mainly in Kern County), and Venturan coastal sage scrub and buck brush chaparral (largely in Ventura County).

- We found recorded instances of 24 listed species on or within 2 km of oil fields with at least 200 hectares altered by hydraulic-fracturing enabled production. Threatened and endangered species occurring in the vicinity of areas highly altered by hydraulic-fracturing-enabled-production are the San Joaquin Valley upland species such as the San Joaquin kit fox, Nelson's antelope squirrel, blunt-nosed leopard lizard, and the giant kangaroo rat, and the California Condor in the Ventura Basin.

- Little data are available to assess the potential impacts of well stimulation on wildlife and vegetation by pathways other than habitat conversion. Factors such as introduction of invasive species, pollution from fluid discharges, water use, noise and light pollution, and vehicle traffic are known to affect wildlife and vegetation, but the extent to which well stimulation affects wildlife and vegetation by those pathways is unknown.

5.8. Conclusions

- With respect to habitat loss and fragmentation, the impact of stimulated wells is not inherently different from that of unstimulated wells. The construction of wells and their support infrastructure disturbs habitat regardless of whether a well is stimulated. Other potential impacts to wildlife and vegetation, such as pollution, could differ between stimulated and unstimulated wells, but we have insufficient data to quantify the effects.

- During the period of 1977 – September 2014, hydraulic fracturing enabled a modest proportion (about 3.5%) of the production that impacts natural habitat in California because most of it occurred in areas that are already highly altered by human activities such as other forms of oil and gas production, agriculture, or urbanization. In turn, oil and gas production as a whole has a much smaller footprint in the state than cities and cultivated land.

- Hydraulic fracturing is becoming an increasingly important driver for enabling oil and gas production in the state. During the period of October 2012 – September 2014, 20% of the land area that was newly developed for oil and gas production could be attributed to hydraulic fracturing.

- Hydraulic-fracturing-enabled activity can be locally important in certain regions, chiefly the southwestern San Joaquin Valley, where frequently stimulated fields overlap with high-quality habitat for rare species, and in Ventura County, where regularly stimulated fields overlap with critical habitat for the California condor and steelhead salmon.

5.9. References

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Chapter Six

Potential Impacts of Well Stimulation on Human Health in California

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6.1. Abstract

This chapter addresses environmental public health and occupational health hazards that are directly attributable to well stimulation or indirectly associated with oil and gas development facilitated by well stimulation in California. Hazards that are directly attributable to well stimulation primarily consist of human exposures to well stimulation chemicals through inadvertent or intentional release to water, air, or soil followed by environmental fate and transport processes. Hazards that are indirectly associated with well-stimulation-enabled oil and gas development also include chemicals and environmental releases. Such hazards may not be directly related to well stimulation, but rather could result from expanded development that is enabled by well stimulation.

The risk factors directly attributable to well stimulation stem largely from the use of a very large number and quantity of stimulation chemicals. The number and toxicity of chemicals used in well stimulation fluids make it impossible to quantify risk to the environment and to human health. To gain insight on the potential of chemicals used in stimulation to harm human health, we used a ranking scheme that is based on toxic hazards of chemicals and reported quantities used in well stimulation operations. The ranking includes both acute and chronic toxicity. (Note that these same chemicals were ranked for aquatic toxicity in Volume II Chapter 2.)

Important pathways for human exposure to well stimulation chemicals and emissions include both water and air pathways. For water, possible pathways leading to exposure in California were identified in Volume II Chapter 2. These pathways include (1) the possibility of shallow hydraulic fractures intersecting protected groundwater, (2) the possibility of hydraulic fracturing intersecting other wells that could provide leakage paths, (3) the potential for spills and leaks of stimulation fluids, (4) injection of produced water, which could contain stimulation chemicals, into protected aquifers, (5) use of produced water that may contain stimulation chemicals in agriculture, (6) disposal of produced water that may contain stimulation chemicals in unlined sumps, and (7) the impact of strong acid use in recovered fluids and produced water. Wastewater generated from stimulated wells in California includes "recovered fluids" (flowback fluids collected into tanks following stimulation, but before the start of production) and "produced water" (water extracted with oil and gas during production). Air pathways that could result in human exposure to chemicals used in well stimulation include atmospheric dispersion of air pollutant emissions to communities near production sites. Studies have found human health risks attributable to emissions of petroleum-related compounds associated with oil and gas development in general. However, public health impacts associated with proximity to oil and gas production have not been measured in California. As such, detailed studies of the relationship between health risks and distance from oil and gas development sites are warranted. In the interim, increased application and enforcement of emission control technologies to limit air pollutant emissions and science-based minimum surface setbacks between oil and gas development and human populations could help to reduce these risks.

Our assessment of the scientific literature for community and occupational exposures and health outcomes indicates that there are a number of potential human health hazards associated with well-stimulation-enabled oil and gas development, but that California-specific peer-reviewed studies are critically scarce, and that air, water, and human health monitoring data have not been adequately collected, analyzed, verified, or reported.

6.2. Introduction

This chapter addresses environmental public health and occupational health hazards that are directly attributable to well stimulation or indirectly associated with oil and gas development facilitated by well stimulation in California.

Hazards that are directly attributable to well stimulation primarily consist of human exposures to well stimulation chemicals through inadvertent or intentional release to water, air, or soil followed by environmental fate and transport processes. Hazards that are indirectly associated with well-stimulation-enabled oil and gas development also include chemicals and environmental releases. Such hazards may not be directly related to well stimulation, but rather result from expanded development that is enabled by well stimulation. A number of potential contaminant release mechanisms and transport pathways have been described in Volume II, Chapters 2 and 3. In this chapter, we extend

the previous discussion of environmental release and environmental transport mechanisms to include potential human exposure pathways, and summarize the hazards in the context of community and occupational health.

Hydraulic fracturing enables some oil and gas development that would not occur without this technology, but any oil and gas development presents hazards to human health through exposure to chemicals. Thus, to the extent that stimulation increases oil and gas development, hazards associated with development will also be increased. For example, additional emissions of toxic air contaminants (TACs) that are directly or indirectly attributable to well stimulation might be small relative to other regional sources (see Volume II, Chapter 3), but might have a higher local health impact near to the point of release. In addition, air pollution associated with the entire operation of oil and gas production can create significant human exposures. Therefore, we extend the discussion of indirect air pollution and emissions from Chapter 3 to consider potential human exposure pathways, and summarize the indirect hazards in the context of community and occupation health.

California-specific data on the impacts of well-stimulation-enabled oil and gas development is insufficient to provide a conclusive understanding of potential hazards and risks associated with well stimulation. Studies conducted outside of California consider health impacts near oil and gas development that are enabled by hydraulic fracturing, but do not differentiate the association of observed health risks between hydraulic fracturing stimulation and oil and gas development in general. Thus, the same health impacts that have been found near oil development enabled by hydraulic fracturing may exist in any oil and gas development.

The approach we take to assess human health hazards follows the general recommendations of the National Research Council (NRC, 1983; 1994; 1996; 2009) to compile, analyze, and communicate the state of the science on the human health hazards associated with well stimulation.

We begin with a summary of all hazards that have been described in earlier chapters of this volume, with an emphasis on human health aspects and risk factors. This provides a single comprehensive list of human health risk factors and hazards for well stimulation activities in California, with reference to the specific locations in the report where each hazard is discussed. We then carry out a detailed assessment of human-health-relevant hazards from chemicals, and from water and air pollution.

Because it is extremely difficult to identify specific causal relationships for a given hazard and health outcome, we employ two alternative approaches to explore hazards associated with a given activity, a bottom-up and top-down approach. The bottom-up approach follows the standard risk assessment framework. In this approach, we characterize the composition of well stimulation fluids and toxic air contaminants associated with well stimulation activities, and then identify chemical-specific human-health-relevant toxicity

data, where available, and rank the chemical hazards based on a combined hazard metric that includes frequency of use, mass used, and toxicity. Our second approach, the top-down assessment, evaluates chemical and physical hazards associated with well stimulation activity by starting with population health outcomes and working backwards to evaluate potential associations between health outcomes and well stimulation activity (or oil and gas development activity, more broadly). To apply the top down approach, we draw from the peer-reviewed literature, where individual outcomes and potential hazards are studied, and findings provide evidence of possible associations between public health hazards and risks. We conclude with a review of occupational-health-relevant regulations and studies and a discussion of noise- and light-pollution health hazards. We identify potential mitigation strategies that, if properly deployed and enforced, may reduce occupational and community health impacts. Finally, we discuss well-stimulation information gaps related to environment protection in California.

As explained in Volume II, Chapter 1, there are both direct and indirect impacts of well-stimulation-enabled oil and gas development that influence public health risks. Based on available evidence, public health risks associated with direct impacts (which are the incremental impacts of oil and gas development attributable to the stimulation process itself and activities directly supporting the stimulation) appear to be small relative to the indirect impacts. To say it another way, the majority of public health risks associated with well stimulation are likely to be indirect, in that they arise from the additional oil and gas development that is enabled by well stimulation. All forms of oil and gas development, not just that enabled by well stimulation, may cause similar public health risks.

As an example, Volume II, Chapter 3 (air) found that benzene and formaldehyde emissions from oil and gas development is a significant fraction of stationary source emissions and may result in elevated atmospheric concentrations in places where people live, work, play, and learn. The current scientific literature has established that benzene is emitted from nearly all oil and gas development (Pétron et al., 2012; Pétron et al., 2014; Helmig et al., 2014). Studies show elevated health risks near hydraulic-fracturing-enabled oil and gas development attributable to benzene (McKenzie et al., 2012). Benzene and formaldehyde are not intentionally added to hydraulic fracturing or other well stimulation fluids, but may be a component of some of the petroleum-based mixtures used in hydraulic fracturing fluids. Overall, the health risks associated with benzene and formaldehyde occur because oil and gas is co-produced—and co-emitted—with these compounds. If public health investigations of benzene exposure were to be conducted only for those exposures near *stimulated* wells, then such investigations would result in a very poor understanding of both the extent of these risks and potentially effective mitigation measures that could protect public health. Concern about the health effects from benzene, formaldehyde, and many other health risks associated with oil and gas development should be approached through studies of oil and gas development from all types of reservoirs, not just those that are stimulated.

6.2.1. Framing the Hazard and Risk Assessment Process

The terms *hazard*, *risk*, and *impact* are often used interchangeably in everyday conversation, whereas in a regulatory context they represent distinctly different concepts with regard to the formal practice of risk assessment. A hazard is defined as any biological, chemical, mechanical, environmental, or physical stressor that is reasonably likely to cause harm or damage to humans, other organisms, or the environment in the absence of its control (Sperber, 2001). Risk is the *probability* that a given hazard will cause a particular harm, loss, or damage as a result of exposure (NRC, 2009). Impact is the particular harm, loss, or damage that is experienced if the risk occurs. Hazard can be considered an intrinsic property of a stressor that can be assessed through some biological or chemical assay. For example, a pH meter can measure acidity, disintegration counters can detect ionizing radiation, cell or whole animal assays, etc. can detect biological disease potency. These types of tests allow us to declare that a substance is acidic, radioactive, a mutagen, a carcinogen, or other hazard. However, defining the probability of harm requires a receptor (e.g., human population) to be exposed to the hazard, and often depends on the vulnerability of the population based on age, gender, and other factors. As a result, risk is extrinsic and requires detailed knowledge about how a stressor agent (hazard) is handled, released, and transported to the receptor populations.

In its widely cited 1983 report, the National Research Council (NRC) first laid out the now-standard risk framework consisting of research, risk assessment, and risk management as illustrated in Figure 6.2-1 (NRC, 1983). The NRC proposed this framework to organize and evaluate existing scientific information for the purpose of decision making. In 2009, the NRC issued an updated version its risk assessment guidance titled “Science and Decisions: Advancing Risk Assessment” (NRC, 2009). This report reiterated the value of the framework illustrated in Figure 6.2-1, but expanded it to include a solutions-based format that integrates planning and decision making with the risk characterization process. The NRC risk framework illustrates the parallel activities that take place during risk assessment and the reliance of all activities on existing research. These activities combine through the risk characterization process to support risk management.

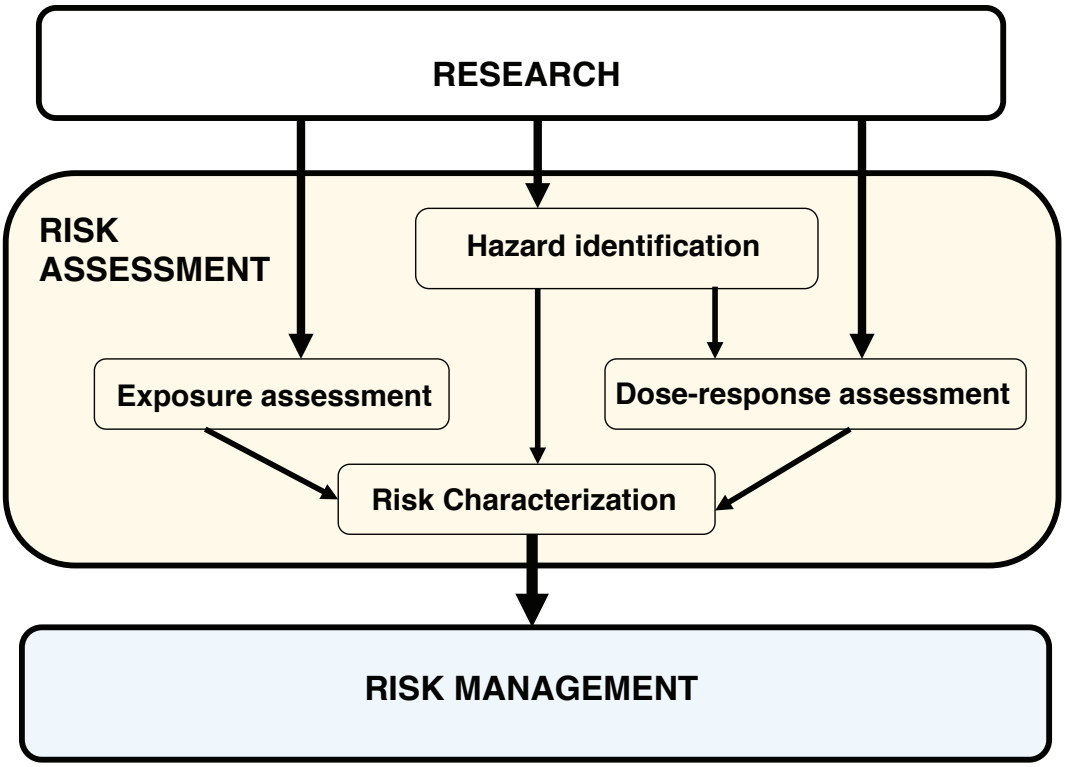


Figure 6.2-1. The NRC (1983) Risk Analysis Framework.

In using the framework in Figure 6.2-1, the first task in the risk analysis process is to identify any feature, event, or process associated with an activity that could cause harm. These are called "hazards." Any given hazard may or may not be a problem. It depends on the answers for two additional questions. First, is the hazardous condition likely to result in a population being exposed to the hazard? Second, what will be the impact if the hazardous exposure does occur (dose-response)? If we know the magnitude of a specific hazard exposure and the relationship between the magnitude of exposure and response or harm, then we can estimate the risk associated with that hazard. In cases where the hazardous condition is unlikely or where, even if it did occur, the harm is insignificant, then the risk is low. Risk is only high when the hazardous condition is both likely to occur and would cause significant harm if it did occur. Of course, there are many combinations of likelihood and harm possible.

Formal risk analysis presents difficulties, because we often lack:

- Data on all the possible hazards;
- Information on the likelihood and magnitude of exposure; and
- Data to support an understanding the relationship between exposure (dose) and harm (response).

If a hazard has not been identified, then it is difficult to develop steps to mitigate potential harm. In this case, a useful approach is to avoid the problem where possible, for example by choosing chemicals that are better understood, less toxic, or more controllable rather than choosing ones for which there is little toxicity information or poor understanding of the relationship between the hazard and risk to the environment and/or to public health. These options for both known and unknown hazards are discussed further in the mitigation section of this chapter as well as in Volume II, Chapter 2, Section 2.4 and in the Summary Report Conclusions.

Although one can attempt to identify *all* hazards associated with well-stimulation-enabled oil and gas development in California, it is important to note that this does not mean that all hazards that are identified present risks. A formal risk assessment is required to estimate risk associated with any given hazard. Although operators can make use of chemicals identified "acceptable" by programs such as the U.S. Environmental Protection Agency (U.S. EPA) Design for Environment Program or the North Sea Gold Ban list, uncertainties about exposure and impact can remain. A formal risk assessment is a significant undertaking that is beyond what was possible in this report. Among the goals of this chapter are to identify community and occupational hazards and highlight those where additional study may be warranted in the context of developing and implementing policies for well stimulation operations.

6.2.2. Scope of Community and Occupational Health Assessment

We consider and include both intentional and unintentional releases of chemical hazards to surface water, groundwater, and air as a direct and indirect result of well stimulation activities. These activities include the transport of equipment and materials to and from the well pad; mixing, handling, and injection of chemicals; and management of recovered fluids/produced water, drill cuttings, and other waste products (NRC, 2014; Shonkoff et al., 2014). In addition, we consider chemical hazards that are produced and/or released during support activities for well stimulation and from stimulated wells, such as: reaction products and mobilized chemical and/or radioactive hazards from the stimulated wells; emissions from generators, compressors, and other equipment during and after stimulation activity; leakage from transfer lines and infrastructure; and accidental spills. Finally, we consider other physical hazards related to well stimulation activity, including elevated noise and light. These hazards are relevant to both community and occupational health.

We exclude hazards associated with the manufacturing of materials, supplies, or equipment that are used in well stimulation activity; hazards from transport of oil and gas to refineries; hazards related to refining; or hazards from the combustion of hydrocarbons as fuel. These hazards, though important, are far removed both temporally and geographically from activities related to the well-stimulation-enabled oil and gas development process. We also exclude economic and psychosocial hazards that may be related to oil and gas development activities and may be important considerations in specific areas, but are beyond the scope of this chapter.

We focus primarily on hazards identified in relevant California-specific datasets and/or in the peer-reviewed literature that is specific to California. We augment this information with hazards identified in peer-reviewed studies conducted outside of California. As pointed out in Volume I and in other chapters in Volume II, geologic conditions and current practice with well stimulation in California can be different from that performed in other states, so not all hazards associated with well-stimulation-enabled oil and gas development outside of California are generally applicable to the California context.

6.2.3. Overview of Approach and Chapter Organization

The objective of this chapter is to catalogue and highlight important *community and occupational health hazards* associated with well stimulation activity in California. This is in contrast to earlier chapters of this volume that focused on environmental hazards in general and specifically those with water, air, and ecological pathways. There is significant overlap among the water, air, and ecological hazards described in earlier chapters and human-health-relevant hazards discussed in this chapter. Therefore, we begin in Section 6.2.4 with a summary of all hazards that have been described in earlier chapters of this volume, with an emphasis on human health aspects and risk factors, and we merge these with hazards that are identified and described in subsequent sections of this chapter. This provides a single list of human-health-relevant risk factors and hazards for well-stimulation-enabled oil and gas development activities in California, with reference to the specific locations in the report where each hazard is discussed. We also link the identified human health hazards to the case studies in Volume III of this report, where some of these hazards are illustrated and/or assessed in specific geographic places. Following the table of human-health-relevant hazards, we provide additional details on each risk factor/hazard combination from the list as well as other hazard/risk factors that are not listed (e.g., coccidiomycosis from exposure to San Joaquin Valley dust) along with recommendations for mitigating of risk.

After reporting and reviewing all human-health-relevant hazards in Section 6.2.4, we conduct a more detailed assessment of human-health-relevant hazards. The remainder of this chapter follows the issues summarized in the table, with the human health hazards (both community and occupational) defined and grouped into the following categories (and the section in which they are discussed):

- *Well stimulation chemicals* (Section 6.3)—includes both hydraulic fracturing and acidization chemicals intentionally injected to stimulate the reservoir or to improve oil and gas production. These chemicals are known and reported by industry on a mostly voluntary basis and more recently under Senate Bill 4 (SB 4, 2014) on a compulsory basis.

- *Recovered fluids and produced water* (Section 6.4)—includes some fraction of the well stimulation chemicals but can also include mobilized chemical compounds, naturally occurring toxic materials (such as radionuclides), and degradation and synergistic by-products from well stimulation chemicals, naturally occurring chemical constituents, and hydrocarbons.

- *Air pollutant emissions associated with well stimulation-enabled oil and gas development* (Section 6.5)—includes combustion products and/or chemical emissions from pumps, generators, compressors and equipment; venting and flaring emissions; dust from well stimulation and land-clearing activities; leaks from transfer lines and/or well heads; longer-term leakage of oil and gas from stimulated wells. (This category does not include emissions from refining and use of the hydrocarbon products.)

- *Occupational Health* (Section 6.6) —includes hazards such as exposure to respirable silica, volatile organic compounds (VOCs), and acids.

- *Other* (Section 6.7)—includes physical hazards such as light and noise and heavy equipment activity, industrial accidents (e.g., loss of well control, explosions), biological hazards such as valley fever in areas where surface soil is disturbed by well stimulation activity, spills from trucks transporting chemicals that can contaminate private wells.

We use the above categories to differentiate hazards that have similar release mechanisms and time of release, such that all chemicals in a given category are likely to be released into the environment by the same mechanism or activity and in the same location. These categories enable us to group hazards identified in this report that are relevant to human and occupational health risk in the summary table below (Table 6.2-1). The specific hazards are listed in terms of the four categories above, along with California-specific factors or conditions (risk factors) that are expected to increase or decrease the human health risk associated with the hazards. All of these risk factors identified in the summary table are applicable to the San Joaquin Valley (SJV), where more than 85% of the well stimulation events in California occur. Some factors also apply to other oil and gas producing regions where well stimulation is used.

In the sections that follow the summary table, we expand on the specific human health hazard categories identified above. In general, when evaluating population-level human-health impacts, it is extremely difficult to identify specific causal relationships for a given

health hazard and impact. As a result, risk assessors consider alternative approaches to assess the likelihood of harm. The first approach, sometimes referred to as "bottom-up," starts with a cause, such as chemical hazard, and attempts to track emissions and exposure pathways along with dose-response modeling to characterize population impact. This approach often must confront uncertainties identifying exposures and actual health impacts. The second approach, sometimes referred to as "top-down," starts with an impact—for example disease incidence—and attempts to track it back to some source chemical or activity. For the "top-down" approach, uncertainty arises from the lack of statistical power in making associations with low disease rates, as well as from the considerable lag times between exposure and occurrence of diseases (e.g., cancer). Because of their significant but different types of limitations, it is useful to consider both approaches. These alternate ways of exploring hazard are illustrated in Figure 6.2-2. In this chapter, we use both approaches.

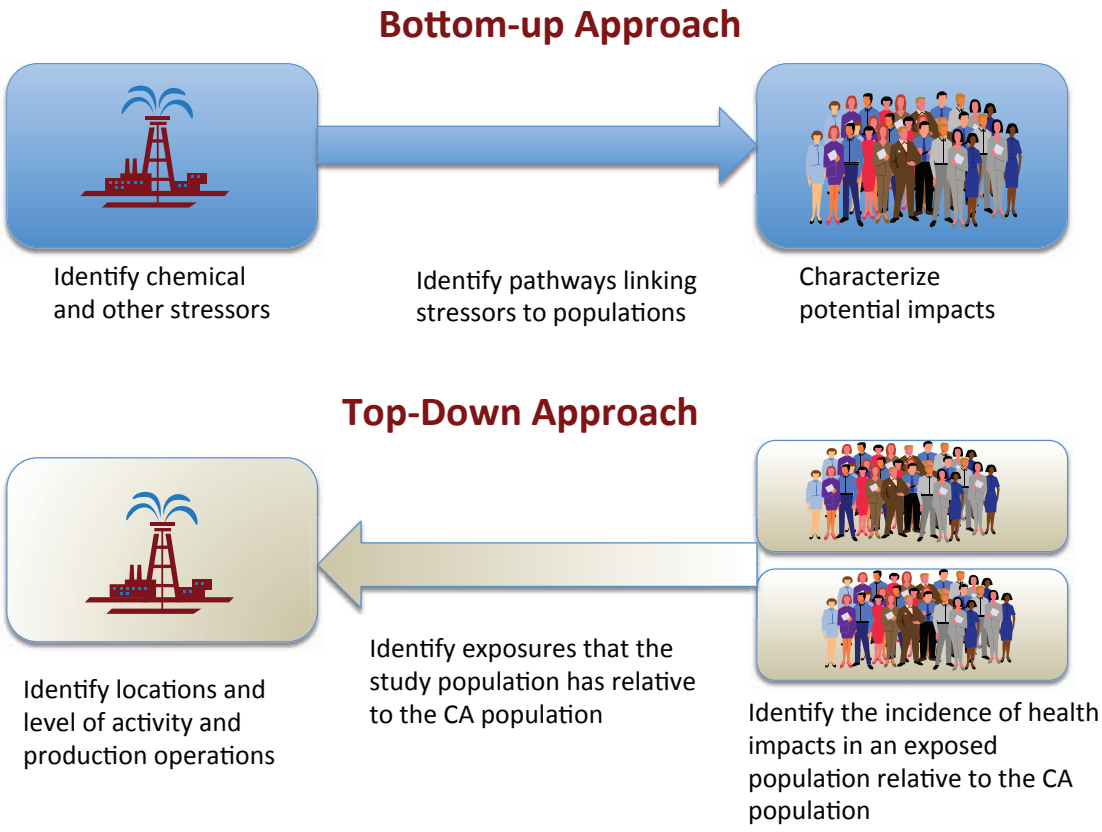


Figure 6.2-2. Illustration of two approaches used to identify human health hazards associated with an activity.

We conduct a bottom-up assessment in Section 6.3, 6.4, and 6.5 where we evaluate chemical and physical hazards associated with well stimulation chemicals and potential contamination pathways. We build on the discussions in Volume II Chapters 2 and 3 that characterize the composition of well stimulation fluids and toxic air contaminants associated with well stimulation activity. We extend this data by identifying chemical-specific human-health-relevant dose-response information where available, and rank the chemical hazards based on a combined hazard metric that includes frequency of use, mass used, and toxicity. We also discuss potential exposure factors to further extend the bottom-up assessment.

The most relevant approach for top-down hazard assessment would be to conduct a formal epidemiological study that attempts to pull out specific cause-effect relationships within a population. However, these studies require that the "effect" already be expressed (and measured) in the population, and that the effect is both unique and common enough to identify. A more general top-down approach draws from the peer-reviewed literature, where individual outcomes and potential hazards are studied, and findings provide evidence of possible associations between hazard and public health risk. We include a top-down hazard assessment in support of each section focusing primarily on California and health-outcome studies and, where studies from outside of California are relevant, we review and summarize the evidence for hazards based on experience and observations from outside California. A detailed summary compilation of the literature is provided in Appendix 6.A for public health, Appendix 6.D for occupational health and Appendix 6.F for noise.

We wrap up the chapter with a summary of critical data gaps (in addition to those identified in earlier chapters) and then with conclusions and recommendations for community and occupation health.

6.2.4. Summary of Environmental Public Health Hazards and Risk Factors

The geology and history of hydrocarbon development, along with current practices and current regulatory framework for well stimulation-enabled oil and gas development in California, give rise to the potential public health risks associated with well stimulation activities. Table 6.2-1 summarizes all human health relevant hazards identified in this chapter and in previous chapters of this volume. We also provide reference to the location in this volume where each risk factor and hazard is discussed in more detail. Although we include possible mitigation strategies in Table 6.2-1, data on the *adequacy and effectiveness* of regulations to achieve these goals is often not available, requires more study, and/or is beyond the scope of this report.

Table 6.2-1. Summary of human health hazards and risk factors in California substantiated with California-specific data.

Risk Factor	Hazard	Description of the issue	How the risk factor is expected to influence public health risks	Possible mitigation	Volume and Section in this Report
Number and toxicity of chemicals in well stimulation fluids	Well stimulation chemicals	Operators have few restrictions on the types of chemicals they can use for hydraulic fracturing and acid stimulation. In California, oil and gas operators have reported the use of over 300 chemical additives. About 1/3 have not been assessed for toxicity. Of the chemicals for which there is basic environmental and health information, only a few are known to be highly toxic, but many are moderately toxic. There is incomplete information on which of the chemicals used have the potential to persist or bio-accumulate in the environment and may present risks from chronic low-level exposure.	If these chemicals are not released into usable water, including agricultural water and to the atmosphere then the risk is minimal. However, if there are leakage and emission pathways then it is nearly impossible to assess the risk because of the large number of chemicals, incomplete knowledge about which chemicals are present, how long these compounds persist and what their environmental and human health impacts are. Researchers and the public need access to sufficient levels of information on all chemicals involved in well stimulation, to begin an assessment of the toxicity, environmental profiles, and human health hazards associated with hydraulic fracturing and acidizing stimulation fluids.	Invoke Green Chemistry principles to reduce risk, that is, use smaller numbers and amounts of less toxic chemicals, and avoid chemicals with unknown impacts. Mitigate exposure pathways. Limit the chemical use in hydraulic fracturing to those on an approved list that would consist only of those chemicals with known and acceptable toxicity profiles.	Vol. II Ch. 2 S. 2.4 & Summary Report S. 3.1
Disposal of water in unlined sumps	Recovered fluids & produced water	The disposal of contaminated water in unlined pits is banned in nearly all other states because such fluids can migrate out of sumps into groundwater and move along with this water to wells or surface water where contamination can be a serious problem. Nearly 60% of wastewater from stimulated wells in California was disposed in unlined sumps.	Well stimulation and naturally occurring chemical constituents can evaporate from these ponds to the atmosphere as air pollutants, leak into aquifers, or migrate through the soil which could lead to food chain exposure to biota and humans. Chemicals in recovered fluids and produced water may be toxic, persistent, or bioaccumulative.	Test and appropriately treat water going in to unlined pits, or phase out the use of unlined sumps in the SJV for wastewater disposal.	Summary Report S. 3.2 & Vol. II Ch. 2 S. 2.6.2.1 & Vol. III Ch. 5

Risk Factor	Hazard	Description of the issue	How the risk factor is expected to influence public health risks	Possible mitigation	Volume and Section in this Report
Beneficial use of produced water	Recovered fluids & produced water	California is a water-short state and California's oil reservoirs produce about 10 times more water than oil. Produced water is sometimes reused, for example to irrigate crops. If this produced water comes from stimulated wells or oil wells producing from a reservoir where stimulation was used, stimulation chemicals could be present in the produced water.	Well stimulation chemicals and their reaction products may be toxic, persistent or bioaccumulative. Current water district requirements for testing such waters before they are used for irrigation are not sufficient to guarantee that stimulation chemicals are removed, although some local treatment plants do use adequate protocols. If produced water used in irrigation water contains well stimulation and other chemicals, this would provide a possible exposure pathway for farmworker and animals and could lead to exposure through the food chain. Currently, more than 60% of the fruits and vegetables consumed domestically come from the Central Valley.	Water districts in the SJV should explicitly disallow the use for irrigation of produced water from wells that have been hydraulically fractured, or demonstrate that their monitoring and treatment methods ensure that hydraulic fracturing chemicals and other contaminants are not present in water destined for irrigation.	Vol. II Ch. 2 S. 2.6.2.3 & Summary Report S. 3.2
Shallow hydraulic fracturing	Well stimulation chemicals	The majority of hydraulic fracturing in California is conducted from shallow vertical wells. These operations present a larger probability of fractures intersecting near-surface groundwater compared to high volume fracturing from deep long-reach horizontal wells commonly used elsewhere.	The groundwater in the vicinity of some shallow fracturing is protected. Contamination of usable groundwater presents environmental public health risks. Groundwater monitoring requirements are likely insufficient to determine whether water has been contaminated by well stimulation-enabled oil and gas development or not. The groundwater in the vicinity of much of the shallow hydraulic fracturing operations in California has high salinity and has no beneficial uses that might constitute environmental exposure pathways to humans.	The focus of regulations should be on preventing contamination of aquifers, not just monitoring for it. Operators should be required to demonstrate that stimulations could not intersect usable groundwater to receive a permit. A higher level of scrutiny should be applied to shallow stimulations. Groundwater monitoring plans should be adapted as part of the corrective action, to improve the monitoring system and specifically look for contamination in close proximity to possible fracture extensions into groundwater.	Vol. I Ch. 3 S. 3.2.3.3 & Vol. II Ch. 2 S. 2.6.2.5

Risk Factor	Hazard	Description of the issue	How the risk factor is expected to influence public health risks	Possible mitigation	Volume and Section in this Report
Hydraulic fracturing in reservoirs with long history of oil and gas production	Well stimulation chemicals Recovered fluids & produced water Air and other pollutant emissions associated with well-stimulation-enabled oil development Other	Many of the issues faced by other states arise because hydraulic fracturing has opened up oil and gas development in regions that previously had little or no experience with production. When the US Energy Information Agency issued a report indicating that a large amount of such development was also possible in California from the Monterey Formation (subsequently revised dramatically downward), many were concerned about the development of oil and gas in new geographies. This assessment finds that the most likely future use of hydraulic fracturing is in and around the reservoirs where it is currently being used.	New production in developed fields can use the existing roads, platforms and infrastructure already in place. As a result, the impacts caused by construction and traffic are much less than in new, previously undeveloped regions.	Existing infrastructure reduces the need for new pads pipelines and other stationary infrastructure. Existing infrastructure can often transport fluids to and from the pad, reducing the need for truck trips. This reduces traffic accidents and the emission of diesel particulates and other health-damaging air pollutants	Vol. II, Ch.. 3
			Old reservoirs have many existing wells. If hydraulic fractures intersect or come near these old wells, the wells could form leakage pathways for stimulation fluids. Older existing infrastructure (e.g. pipelines, storage tanks) may increase the likelihood of failures or leakage.	Locate and seal old wells in the vicinity of hydraulic fracturing if they would provide leakage paths to air and usable groundwater. Regulations should explicitly require an assessment of the integrity and leakage risk of existing wells that might be encountered by a hydraulic fracture, and remediation of wells which create a high risk of leakage into water less than 10,000 milligrams/liter total dissolved solids.	Vol. II Ch. 2 S. 2.6.2.6 & Vol. III Ch. 5 and Ch.2, Table 2.6-1.
Injection of recovered fluids and produced water into aquifers used for drinking, agriculture, and other direct and indirect uses by humans	Well stimulation chemicals Recovered fluids & produced water	Produced water from stimulated fields has been injected into aquifers that are suitable for drinking water, irrigation, and other beneficial uses.	If water from contaminated aquifers is used, it could expose humans to unsafe concentrations of toxic compounds.	Prevent injection of well stimulation chemicals to usable groundwater in the future. In the process, of reviewing, analyzing and remediating the potential impacts of wastewater injection into protected groundwater, consider the possibility that stimulation chemicals may have been present in these wastewaters.	Vol. II Ch. 2 S. 2.6.2.2 & Vol. III Ch. 5

Risk Factor	Hazard	Description of the issue	How the risk factor is expected to influence public health risks	Possible mitigation	Volume and Section in this Report
Spills and leaks	Well stimulation chemicals Recovered fluids & produced water	Surface spills and leaks are common occurrences in the oil and gas industry and must be reported and cleaned up.	Information recorded on spills and leaks is insufficient to determine whether stimulation chemicals could be involved.	Require public reporting about whether the source of the leak could contain well stimulation chemicals.	Vol. II Ch. 2 S 2.6.2.9
Oil and gas development near human populations	Well stimulation chemicals Recovered fluids & produced water Air and other pollutant emissions associated with hydraulic fracturing-enabled development Other	California has large oil reserves located under densely populated areas primarily in the San Joaquin and Los Angeles Basins. In Los Angeles, oil and gas production developed simultaneously with the growth of the city. The Los Angeles Basin has world-class oil reservoirs, with the most concentrated oil in the world. Los Angeles is also a global megacity.	Proximity to production increases exposures to air pollutant emissions and other results of oil and gas development activities (e.g., dust, chemicals, noise, light). Households that use groundwater from private drinking water wells in close proximity to oil and gas development may be at increased risk of exposure to potential water contamination.	Identify and apply appropriate measures to limit exposure by residents and sensitive receptors such as schools, daycare facilities and elderly care facilities such as scientifically based setback requirements.	Vol. II Ch. 6S. 6.8.1 & Vol. III Ch. 4.3 & Summary Report S. 3.2
Acid use	Well stimulation chemical	Operators in California commonly use mixtures of hydrochloric acid and hydrofluoric acid with other sources of fluoride anions as the most economical reagent for cleaning out wells or enhancing geological formation permeability. Reported use of hydrofluoric acid in the SCAQMD data lists the concentration as percent mass in the ingredient as 1%-3%.	Spills and leaks of undiluted acids may present an acute toxicity and corrosivity hazard. The use of acid can also mobilize naturally occurring heavy metals and other compounds that are known to be health hazards and these compounds could therefore be present in recovered fluids and produced water which humans could be exposed to if treatment and disposal is not sufficiently undertaken.	Evaluate the chemistry of recovered fluids and produced water for wells that have used acids and the potential consequences for the environment. Require reporting of significant chemical use for oil and gas development based on these results.	Vol. II Ch. 2 Ss. 2.4.3.2, 2.6.2.9 & Summary Report S. 3.2

6.3. Public Health Hazards of Unrestricted Well Stimulation Chemical Use

Previous chapters have considered environmental and ecological hazards. In this section, we examine the potential impact of well stimulation chemicals on human health, based on reported use information (frequency and quantity) and on published toxicity information.

The majority of important potential direct impacts of well stimulation result from the use of chemicals. Operators have few restrictions on the types of chemicals they use for hydraulic fracturing and acid treatments. In California, oil and gas operators have reported, on voluntary and mandated bases, the use of over 300 chemical additives (see Volume II, Chapter 2 for detailed description of chemicals). Although SB 4 (2014) now mandates reporting of chemical use by operators, the data are not subject to independent verification, and chemicals can be reported as "trade secrets," meaning they need not be fully identified. The many chemicals used in well stimulation makes it very difficult to judge the public health risks posed by releases of stimulation fluids.

In addition to the sheer number of known and unknown (trade-secret) chemical additives used, we often lack information on potential release mechanisms and important physical and chemical properties needed to characterize environmental fate and exposure pathways, and toxicological characteristics (acute and chronic) needed to fully understand chemical hazards.

The most common toxicity information about chemicals is from standardized mammalian acute toxicity tests that measure the short-term (minutes to hours) exposure concentration or one-time dose of a chemical required to induce a well-defined response (death, narcosis, paralysis, respiratory failure, etc.) of a test animal, most commonly rats and mice. Such tests are used to assess toxicity of inhalation, ingestion, and/or uptake through the skin. Acute toxicity tests measure extreme outcomes, but the tests are useful for ranking chemicals against each other and identifying chemicals that are clearly dangerous if taken into the body.

More useful but less commonly available tests for health impacts are chronic toxicity tests. These are long-term studies (often lifetime or multi-generation studies) with small mammals to observe any increases in chronic disease incidence—including tumors and cancer, reproductive/developmental changes, neurological damage, respiratory damage, life shortening. Animal-based chronic toxicity results are used for assessing the hazards and risks to communities and workers from long-term (up to lifetime) exposures to relatively low concentrations or doses of chemicals. In addition to toxicity tests with animals, some chemicals have occupational or community epidemiological studies that provide useful information on chronic toxicity. Because these studies are the result of accidents or from improperly regulated chemicals or air contaminants, there are limited numbers of chemicals that have human-based chronic health data. Approximately two-thirds of the reported chemicals used in well stimulation have publically available results from acute mammalian toxicity tests (excluding material safety data sheets (MSDS) data), and only about one-fifth of the reported chemicals have associated chronic toxicity information.

Of the chemicals for which there is basic environmental and health information, only a few are known to be highly toxic, but many are moderately toxic. For most substances we consider, there is lack of toxicological testing for long-term chronic exposure at very low levels. There is also a lack of testing on mixtures. Some of the chemicals used may have the potential to persist or bio-accumulate in the environment and present risks from chronic low-level exposure. Because the toxicology for multiple routes of exposure—inhalation, ingestion, skin contact, etc.—is rarely reported, cumulative exposure assessment is beyond the scope of our analysis.

In this section, we develop and apply a semi-quantitative ranking system for chemical hazards associated with well stimulation activity. The ranking system is not a substitute for field observations or a full risk assessment, but provides an initial focus on which chemicals are of highest concern and which are of lower priority. Section 6.3.1 describes the approach, followed by results for hydraulic fracturing chemicals, acidization chemicals, and toxic air contaminants in Section 6.3.2, finishing with a summary of relevant literature in Section 6.3.3.

6.3.1. Approach for Human Health Hazard Ranking of Well Stimulation Chemicals

Chemical hazards include both hydraulic fracturing and acidization chemicals that are intentionally injected to stimulate the reservoir or to improve oil and gas production (see Volume I, Chapter 2 for the engineering purpose of these chemicals) and unintentional releases from spills or leaks. Chemicals are used in the drilling and well stimulation processes for a variety of purposes, including as corrosion inhibitors, biocides, surfactants, friction reducers, viscosity control, and scale inhibitors (Southwest Energy, 2012; Stringfellow et al., 2014) (Section 2.4.4.1). Hydraulic fracturing uses fluids or gels that contain organic and inorganic chemical compounds, a number of which are known to be health damaging (Aminto and Olson, 2012).

In this section, we provide a bottom-up assessment to develop hazard priorities for chemicals that are used in well stimulation. The ranking is based on reported information about the specific chemical identity, the quantity and frequency of use, and available information on both acute and chronic toxicity.

6.3.1.1. Chemical Hazard Ranking Approach

Well stimulation (e.g., hydraulic fracturing and acidization) includes processes that use, generate, and release (intentionally and unintentionally) a wide range of chemical, physical, and, in some cases, biological stressors. To organize the large and diverse number of potential stressors, we use a hazard-ranking scheme that begins with a list of all identifiable stressors, and then records for each stressor our attempts to characterize potential outcomes, using measures of toxicity combined with information representing the frequency and magnitude of use. Sections 6.4 and 6.5 describe potential exposure pathways that would bring chemicals to a human population through water supply or air.

The hazard-ranking scheme used here gives weight to three factors— the number of times a chemical is reported in the database (a surrogate for frequency of use), mass or mass fraction (concentration) used, and toxic hazard screening criterion. So it is not the most toxic substances that always rank high, because weight is also given to substances of intermediate toxicity (or even relatively low toxicity) that are used frequently and/or in large quantities. Even with high mass and frequent use of compounds with elevated toxicity, an exposure pathway is required to bring the compound into contact with the human receptor for an adverse effect to be realized.

The disclosed mass and frequency of chemical use (as described in Section 2.4.3 for hydraulic fracturing and in Section 6.3.2.2 for acidization) provides a surrogate for potential chemical release and exposure, but this is only part of the hazard picture. It is also important to consider the impact of exposure to a chemical. Impacts considered in this assessment include both acute and chronic toxicity outcomes for individual chemicals. As noted above in Section 6.3, toxicity can be characterized as acute (short-term consequences from a single exposure or multiple exposures over a short period) or chronic (long-term consequences from continuous or repeated exposures over a longer period). It is not possible to evaluate potential synergistic hazards with multiple pollutants at this time.

For acute toxicity, we use a screening hazard criterion based on the Global Harmonization Score (GHS) that combines all acute toxicity information into a single screening value (UN, 2011). For chronic toxicity, we use published regulatory reference levels that consider information reported for different routes of exposure (inhalation, ingestion, dermal) and different health outcomes.

The ultimate goal of the hazard ranking is to combine the different elements that relate to increasing hazard. In considering specific chemical stressors, we used the information on frequency of use, mass or mass fraction used per treatment, and acute and/or chronic health hazard criteria, to develop a potential hazard score that could be used to assign a rank for each substance. In cases where all three pieces of information are available, the hazard score is calculated as an Estimated Hazard Metric (EHM) given by:

$$\text{EHM} = (\text{frequency of use}) \times (\text{mass or mass fraction used})/(\text{toxicity criterion})$$

The calculated EHM are used to rank all substances from highest estimated hazard to lowest. For chemicals that lack sufficient information to calculate an EHM, we ranked from most toxic to least toxic, and when toxicity information is lacking we rank from most to least reported use. The resulting sorted list provides an indication of level of concern for each compound.

The development of acute and chronic toxicity criteria used for calculating the EHM are discussed in Sections 6.3.1.2 and 6.3.1.3, respectively, with the hazard ranking results for hydraulic fracturing and acidization presented in Sections 6.3.2.1 and 6.3.2.2, respectively.

6.3.1.2. Acute Toxicity Hazard Screening Criterion

Human hazards associated with acute or short-term exposures are inferred from laboratory studies that examine the acute toxicity of an individual compound or chemical formulations through standardized testing procedures using mammals—typically mice, rats, and rabbits. In these studies, the test animals are exposed to high concentrations of the test chemical and the response of the animals as a function of the exposure is determined, with the metric being the concentration at which some significant fraction of the animals have a measurable outcome (05%, 10%, 50%). These effective concentrations (EC) or effective doses (ED) are reported as respectively EC05 (EC05), EC10 (ED10), and EC50 (ED50).

We collected acute toxicity data for the chemicals that have been disclosed in well stimulation fluid in California that were definitively identified by their Chemical Abstract Service Registration Numbers (CASRN). Toxicity data were gathered from publicly available sources as described in Volume II, Chapter 2 and from MSDS. Acute toxicity data is available for a number of exposure routes and a range of effects. To merge this diverse data set into a single health-screening criterion, we used the United Nations Globally Harmonized System of Classification and Labeling of Chemicals (GHS). The GHS is a system for categorizing chemicals based upon their LD50 (lethal dose) or EC50 values (UN, 2011). In the GHS system, lower numbers indicate more toxicity, with a designation of "1" indicating the most toxic compounds. Chemicals for which the LD50 or EC50 exceeded the highest GHS category were assigned a value of 6 and classified as non-toxic. Chemicals that lack data on acute effects were assigned a GHS value of zero.

We also reviewed material safety data sheets (MSDS) for each chemical and recorded GHS values for a range of outcomes, including acute dermal, skin irritation, eye effects, respiratory sensitization, and skin sensitization. The GHS values from publicly available sources (oral and inhalation) were assessed separately from the GHS scores reported in MSDS.

Because the GHS is reported on a scale of 1 to 5, we found it to be ineffective for sorting out highly toxic chemicals. To address this issue for human health impacts, we converted the GHS category scores back to the midpoint exposure concentration for animal oral toxicity in milligrams per kilogram (mg/kg) for the given category, based on the definitions provided for GHS categories (Table 3.3-1 in UN, 2011). GHS categories 1, 2, 3, 4, and 5 were assigned equivalent toxicity criteria of 2.5, 25, 200, 1,150, and 3,500 mg/kg, respectively. We refer to this as the GHS-surrogate-concentration or "GHS-sc."

Most stimulation chemicals are used at fairly low concentrations, usually less than 0.1%. These concentrations can be well below concentrations that would cause test animals to have a measureable acute response. However, most chemicals that have been assessed for toxicity are assessed with acute toxicity tests. Low-concentration responses are difficult to measure but highly relevant to efforts to protect human health. Public health actions are intended to prevent harm before it happens, rather than provide methods to monitor harm as it happens. This goal reflects the need for chronic hazard screening as a key supplement to acute hazard screening.

6.3.1.3. Chronic Toxicity Hazard Screening Criterion

Chronic toxicity values are typically expressed using a long-term average intake that is considered a "safe" or no-effect dose, expressed in mg/kg (body weight) per day. For example, the state of California issues reference exposure levels (RELs) in milligrams per kilogram per day (mg/kg/d) for a number of non-cancer chemicals. Acceptable chronic exposure levels for cancer-causing chemicals are selected to assure a minimum cancer risk, such as below 1 in 100,000. In developing a screening criterion for chronic toxicity, we select a single chronic screening score (CSS), which reflects the lowest acceptable chronic exposure in mg/kg/d across a broad range of chronic outcomes. Chronic health hazard screening values for hydraulic fracturing and acidizing fluid-treatment chemicals were developed from several sources of chronic toxicity information compiled by California and federal health agencies. These values indicate the likelihood of an adverse health outcome from repeated or continuous exposure over the long term.

Chronic toxicity screening criteria were developed separately for inhalation and oral exposure. Details on the compilation of chronic screening scores (CSS) for well stimulation chemicals are provided for the inhalation and oral routes of exposure in the following sections.

6.3.1.3.1. Chronic Screen Scores for the Inhalation Route

The following sources were used to identify screening values for the inhalation route of exposure.

1. Office of Environmental Health Hazard Assessment-derived (OEHHA) Reference Exposure Levels (RELs) for non-carcinogenic toxicants, and inhalation Unit Risk values (URs) for carcinogens (OEHHA, 2008; 2014a);

2. U.S. EPA toxicity criteria, which are similar to the OEHHA criteria in both form and method of derivation. U.S. EPA develops Reference Concentrations (RfCs) for non-carcinogens and Unit Risk Estimates (UREs) for carcinogens1 (U.S. EPA, 2014a; 2014b);

3. Agency for Toxic Substances and Disease Registry (ATSDR) Minimal Risk Levels (MRLs) for non-carcinogens, also similar to the OEHHA REL values (ATSDR, 2014).

1. U.S. EPA's Integrated Risk Information System (IRIS) was used as the primary source of information from U.S. EPA. In some cases, additional values were based on Provisional Peer Reviewed Toxicity Values (PPRTVs) derived by U.S. EPA's Superfund Health Risk Technical Support Center, or U.S. EPA's Health Effects Assessment Summary Tables.

For purposes of comparison, the available dose-response values were converted into a consistent scale of measurement, namely, a reference concentration in units of milligrams per cubic meter (mg/m3). Details and assumptions for calculating screening level dose-response values for chronic inhalation exposure are provided in Appendix 6.B. The reference concentrations were then converted to mg/kg/d equivalent dose, assuming a 20 m^3(5,283 gallons)/day inhalation rate and 70 kg (154 lbs) body weight. This value is meant only for ranking hazards across different routes of exposure; the original regulatory reference concentrations should be used in any subsequent assessment of risk.

6.3.1.3.2. Screening Values for the Oral Route

The following sources of toxicity information were used to identify hazard-screening values for the oral route of exposure:

1. OEHHA-derived values: Public Health Goals (PHGs) and Maximum Contaminant Levels (MCLs) for drinking water, "No Significant Risk Levels" (NSRLs), and Maximum Allowable Dose Levels (MADLs) for carcinogens and reproductive toxicants listed under Proposition 65 (OEHHA, 2014a; 2014b);

2. U.S. EPA: oral Reference Doses (RfDs) and cancer Slope Factors (SFs) (U.S. EPA, 2014a; 2014b);

3. ATSDR MRLs for oral exposure (ATSDR, 2014).

Oral route toxicity screening values are presented as mg/kg/d of oral intake. For details on derivation of chronic toxicity screening value for oral dose in this report, see Appendix 6.B.

6.3.2. Results of Human-Health Hazard Ranking of Stimulation Chemicals

This section provides results ranking hazards for chemical additives in hydraulic fracturing fluids (Section 6.3.2.1) and in acidization fluids (Section 6.3.2.2). In addition, we review hazards for chemicals released during well stimulation activity that are not directly added to the well (Section 6.3.2.3).

6.3.2.1. Hazard Ranking of Chemicals Added to Hydraulic Fracturing Fluids

The hazard ranking for hydraulic fracturing fluids is derived for all substances reported to be used in hydraulic fracturing that were definitely identified by CASRN. Additives without CASRN identification could not be assessed for toxicity screening values and thus were not included in the hazard ranking analysis. However, the absence of definitive identification for a chemical should not be interpreted as an indication that the specific additive is not hazardous.

For each disclosed additive, we use the available information on frequency of use in well stimulation (Section 2.4.3.1), quantity used (median concentration used across all well stimulation events) (Section 2.4.3.2), along with the GHS-based toxicity screening criterion for acute mammalian toxicity (normalized to exposure concentration as described in Section 6.3.1.2), and chronic screening values normalized to dose as derived from published values and regulatory values. We rank the acute and chronic hazards separately, and we include separate chronic rankings to reflect intake by inhalation or oral routes. For the acute toxicity information, we often had to rely on information that was only on material safety data sheets (MSDS), which is not always reliable but often the only toxicity information for specific health outcomes (e.g., eye irritation or sensitization). In cases where toxicity information from other published sources is available, we include separate hazard rankings using for results from material safety data sheets (MSDS) and from published sources. We base the ranking on the minimum, or most conservative, acute hazard value for each hazard ranking (i.e., with and without using MSDS data).

Out of 320 substances identified in the chemical disclosures (Table 2.A-1), 227 were definitively identified. We identified acute hazard screening values for 176 substances and chronic screening values for 56. The acute screening values are reported in Appendix 6.C Table 6.C-1. The chronic screening values are reported in Appendix 6.C Table 6.C-2. Four of the 56 compounds with chronic screening values did not have acute screening values, so we had a total of 176 compounds out of 320 (55%) for which we could develop a complete hazard ranking. There are an additional 23 compounds reported for which we have CASRN, but no information on frequency of use or mass used. Of these 23, we have an acute and/or chronic hazard screening value for 17. There are 121 substances for which we have generic descriptors (“trade secrets”) and frequency of use information, but no CASRN identifications or toxicity information (note that chemicals without CASRN were not reviewed for toxicity). In Table 6.3-1 below, we summarize our findings regarding the different combinations of known versus unknown factors for reported hydraulic fracturing chemical additives.

Table 6.3-1. Available and unavailable information for characterizing the hazard of stimulation chemicals used in hydraulic fracturing.

Number of chemicals	Proportion of all chemicals	Identified by unique CASRN	Impact or toxicity	Quantity of use or emissions
176	55%	Available	Available	Available
17	5%	Available	Available	Unavailable
6	2%	Available	Unavailable	Available
121	38%	Unavailable	Unavailable	Available

Following the approach described above, we used information on frequency of use, quantity used, and health hazard screening criterion to derive an estimated acute hazard metric (EHM_{acute}) score for each of the 176 substances used in hydraulic fracturing that had sufficient information to make this calculation. All 176 EHM_{acute} scores are provided in

Table 6.C-1. The scores range over six orders of magnitude from 0.003 to 4,000. These are relative scores with higher values associated with higher concern. We used these scores to sort the substances from high to low. Table 6.3.2 lists the 12 substances with the highest EHM_{acute} values and identifies what factor(s) contribute most to this score—frequency of use, quantity used, and/or toxicity. The footnote to Table 6.3-2 indicates the acute toxicity and source of information for each chemical. Substances that did not have sufficient information to calculate EHM_{acute} values are sorted from low to high on a toxicity criterion; then for chemicals that lack a toxicity criterion, we sorted from high to low on frequency of use, then mass used, and finally the last chemicals are simply sorted alphabetically in Table 6.C-1.

Table 6.3-2. A list of the 12 substances used in hydraulic fracturing with the highest acute Estimated Hazard Metric (EHM_{acute}) values along with an indication of what factor(s) contribute most to their ranking (from high to low).

Chemical Name	Reported frequency of use	Reported median mass fraction per WST (mg/kg)	Acute Toxicity
Distillates, petroleum, hydrotreated light paraffinic	✔	✔	
Isotridecanol, ethoxylated	✔		✔[1]
Hydrochloric acid		✔	✔[2]
Polyethylene-polypropylene glycol	✔		✔[3]
Sodium hydroxide			✔[4]
Glyoxal		✔	✔[5]
Potassium carbonate	✔	✔	
Glutaraldehyde			✔[6]
Ammonium Persulfate	✔		✔[7]
Hydrofluoric acid		✔	✔[8]
Sodium tetraborate decahydrate	✔	✔	
5-Chloro-2-methyl-3(2H)-isothiazolone	✔		✔[9]

[1] Skin corrosion/irritation GHS = 1 per MSDS; [2] Skin sensitization and eye effects GHS = 1 per MSDS; [3] Inhalation LC50 for rats of 45 ppm equivalent to GHS 1 from published data; [4] Skin corrosion/irritation GHS = 1 per MSDS; [5] Eye effects GHS = 1 per MSDS; [6] Inhalation equivalent to GHS 1 per published values and Eye effects GHS = 1 per MSDS; [7] Respiratory sensitization GHS = 1 per MSDS; [8] Inhalation equivalent to GHS 2 per published values and dermal, skin corrosion/irritation and eye effects per MSDS; [9] Inhalation equivalent to GHS 1 per published values

In developing a chronic hazard metric (EHMchronic) score, we again make use of frequency of use, mass used per treatment, and health-hazard screening criterion for each of 55 substances used in hydraulic fracturing that had sufficient information to make this calculation. All 55 EHMchronic scores are provided in Table 6.C-2. The scores range over nine orders of magnitude from 200 to 400,000,000,000 and tend to be higher for

the inhalation route compared to the oral route. These are relative scores with higher values associated with higher concern. We used these scores to sort the substances from the highest to lowest estimated EHMchronic sorted on the average rank across inhalation and oral routes. The median chronic score is around 1 million. The top 12 substances for chronic hazard all have EHMchronic values over 1 million. Table 6.3-3 lists the 12 substances with the highest EHMchronic values and identifies what factor(s) contribute most to this score—frequency of use, quantity used, or toxicity. Substances with neither an EHM_{acute} or EHMchronic value are listed in Table 6.C-1, but not repeated in Table 6.C-3.

Table 6.3-3. A list of the 12 substances used in hydraulic fracturing with the highest chronic Estimated Hazard Metric (EHMchronic) values along with an indication of what factor(s) contribute most to their ranking (from high to low).

Chemical Name	Reported frequency of use	Reported median conc. per WST (mg/kg)	Chronic[8] Toxicity
Proppant material[1]		✔	✔[1]
Glutaraldehyde	✔	✔	✔
Zirconium oxychloride	✔	✔	✔[2]
Bromic acid, sodium salt (1:1)		✔	✔[3]
Hydrochloric acid	✔	✔	✔
Boron sodium oxide	✔	✔	✔[4]
Ethylbenzene		✔	✔
Naphthalene	✔		✔
Sodium tetraborate decahydrate	✔	✔	✔[5]
Boric acid, dipotassium salt		✔	✔[6]
Aluminum oxide		✔	✔[7]
Diethanolamine		✔	✔[6]

[1] Proppant materials reported that might include Crystalline silica impurity (Mullite, Kyanite, Silicon dioxide) use Crystalline silica impurity as reference chemical for hazard screening (inhalation); [2] Soluble Zirconium compounds used as reference chemical for hazard screening (oral); [3] Boric Acid and Bromate used as reference compound for hazard screening (oral) and (inhalation) respectively; [4] Boric acid used as reference chemical for hazard screening (oral); [5] Boric Acid used as reference compound for hazard screening (oral); [6] Boric acid used as reference chemical for hazard screening (oral); [7] The toxicity value used is only for non-fibrous forms of aluminum oxide, and does not apply to fibrous forms; [8] Screening toxicity values for aluminum oxide, titanium oxide, propargyl alcohol, glyoxal, butyl glycidyl ether, hydrogen peroxide, and ethanol are available for occupational health criteria but screening values are not provided because for each of these substances, there was an indication in the literature of possible mutagenicity or carcinogenicity such that the available occupational health criteria might not be sufficiently health protective of workers and the general population.

6.3.2.2. Hazard Ranking of Acidization Chemicals

The data used to characterize hydraulic fracturing fluids did not include disclosed acidization events. However, the South Coast Air Quality Management District (SCAQMD) rule 1148.2 mandates that operators disclose the chemicals used in oil and gas development activities that include acidization. Acidization events are defined for the purpose of this review as events that include hydrochloric acid (HCl) and/or hydrofluoric acid (HF). The data that meets the definition of an acidization event were exported from data entered into the SCAQMD database between July 2013 and May 2014. The data include 243 events in 243 wells with a total of 8,549 entries for individual chemicals or "trade secrets" (listed by chemical family). The actual date of each event is not listed, but it appears that most of the data was entered into the database between March and May of 2014.

As with the hydraulic fracturing fluid disclosures, not all additives in the acidization events were clearly identified. Between 3 and 21 lines (ingredients in the acidization event) for each event are reported as trade secret, with no information provided on mass, composition, or definitive chemical identification. A total of 87 definitively identified chemicals are listed for the acidization events with 33 chemicals unique to acidization (i.e., not used in hydraulic fracturing). The remaining 54 chemicals are used in both acidization (per SCAQMD disclosures) and hydraulic fracturing (per FracFocus disclosures). It is unclear which if any disclosures for specific events are included in both databases.

Twenty-six chemicals were listed more than 50 times in the acidization notices, with methanol (n = 532), hydrochloric acid (n = 436) and propargyl alcohol (n = 272) being the most commonly reported chemicals used in acidization events (excluding water). There are 45 chemicals listed fewer than five times. Data are not available to assess the coverage of the SCAQMD disclosures relative to all acidization treatments in California, but clearly the data provided in the SCAQMD database are specific for activity in the South Coast Air Basin which includes Orange County and the non-desert regions of Los Angeles and Los Angeles County, San Bernardino County, and Riverside County.

Twelve chemicals are reported with median application rate greater than 200 kg per event, but several of these are either base fluid or proppant material. The reporting of proppant indicates that there may be some overlap between acidization treatments and fracturing treatments in the SCAQMD database. The remaining high-use chemicals in the list include primarily acids and buffering compounds. For chemicals that are used in both hydraulic fracturing and in acidization treatments, a comparison of the reported mass used indicates that there is no correlation ($r^2 = 0.01$) between median mass reported for specific compound used in the SCAQMD acidization treatments and the FracFocus/DOGGR (Division of Oil, Gas and Geothermal Resources) hydraulic fracturing treatments.

In order to develop a hazard ranking for acidizing fluids, we follow the procedure outlined above for hydraulic fracturing fluids to compile a list of all substances for which we had CASRN and provided, for each chemical, any available information on frequency of use

in well stimulation, quantity used in each well stimulation, the GHS screen criterion for acute toxicity, and available chronic screening criteria. The frequency used and quantity used are specific to the acidization treatments and differ from values reported for the same chemical in the assessment of hazard for stimulation chemicals used in hydraulic fracturing (previous section). The data used to assess acidization did not provide information that would allow the calculation of mass fraction or concentration as used in the hydraulic fracturing assessment above, so the media mass (kg) used across all events was used as a surrogate for quantity. The acute screening values for acidization chemicals are reported in Appendix 6.C, Table 6.C-3. The chronic screening values are reported in Appendix 6.C, Table 6.C-4. Out of 165 uniquely identified additives (or products), 78 compounds were identified with CASRN, 48 had both quantity and toxicity information, and 39 had only quantity information. In Table 6.3-4 below, we summarize our findings regarding these different combinations of known versus unknown factors.

Table 6.3-4. Available and unavailable information for characterizing the hazard of stimulation chemicals use in acidizing.

Number of chemicals	Proportion of all chemicals	Identified by unique CASRN	Impact or toxicity	Quantity of use or emissions
48	29%	Available	Available	Available
0	0%	Available	Available	Unavailable
39	24%	Available	Unavailable	Available
78	47%	Unavailable	Unavailable	Unavailable

Following the approach described above and used for hydraulic fracturing chemicals, we used the information on frequency of use, quantity used, and toxicity screening criterion to derive an estimated acute hazard metric (EHM_{acute}) score for each of the 48 substances used in acidization that had sufficient information to make this calculation. All 48 EHM_{acute} scores are provided in Table 6.C-3 along with information for other substances for which the score could not be determined. The scores range over eight orders of magnitude from 0.002 to 150,000. These are relative scores with higher values associated with higher concern. We used these scores to sort the substances from high to low on the average EHM between results, including MSDS data and results based on published toxicity data. The median score is around 1. Table 6.3-5 lists the 10 substances with the highest EHM_{acute} values and identifies what factor(s) contribute most to this score—frequency of use, quantity used, or toxicity. Substances with no EHM_{acute} are sorted by decreasing concentration.

In developing a chronic hazard metric (EHMchronic) score for acidization chemicals, we again make use of frequency of use, mass used per treatment, and health hazard screening values for each of 17 substances used in acidization that had sufficient information to make this calculation. All 17 EHMchronic scores, along with toxicity and use-frequency data for substances that did have reported mass used, are provided in Table 6.C-6. The scores range over eight orders of magnitude from 10 to 800,000,000, and tend to be higher for the inhalation route than the oral route. These are relative scores with higher

values associated with higher concern. We used these scores to rank the substances from 1 to 17, with 1 being the greatest estimated hazard rank. The median chronic score is around 10,000. Table 6.3-6 lists the 10 substances with the highest EHMchronic values and identifies what factor(s) contribute most to this score—frequency of use, quantity used, or toxicity.

Table 6.3-5. A list of the 10 substances used in acidization with the highest acute Estimated Hazard Metric (EHM_{acute}) values, along with an indication of what factor(s) contribute most to their ranking (from high to low).

Chemical Name	Reported frequency of use	Reported median mass per WST (kg)	Acute Toxicity
Hydrochloric acid	✔		✔[1]
Hydrofluoric acid	✔		✔[2]
Potassium chloride		✔	
Ammonium Chloride	✔	✔	✔[3]
Citrus Terpenes			✔[4]
2-Butoxyethanol (Ethylene glycol butyl ether)	✔		✔[5]
Propargyl alcohol	✔		✔[6]
Acetic Acid			✔[7]
Crystalline silica quartz		✔	
Citric acid	✔	✔	✔[8]

[1] Skin sensitization and eye effects GHS = 1 per MSDS; [2] Inhalation equivalent to GHS 2 per published values and dermal, skin corrosion/irritation and eye effects per MSDS; [3] Eye effects GHS = 2 per MSDS; [4] Skin corrosion/irritation GHS = 1 and eye effects GHS = 2 per MSDS; [5] Inhalation effects GHS 2 from published data and eye effects GHS = 2 per MSDS; [6] Oral effects GHS 2 from published data and numerous effects with GHS = 1 or 2 per MSDS; [7] Skin corrosion/irritation GHS = 1 and eye effects GHS = 1 per MSDS; [8] Eye effects GHS = 2 per MSDS

Table 6.3-6. A list of the 10 substances used in acidization with the highest chronic Estimated Hazard Metric (EHMchronic) values along with an indication of what factor(s) contribute most to their ranking (from high to low).

Chemical Name	Reported frequency of use	Reported median mass per WST (kg)	Chronic Toxicity
Hydrochloric acid	✔		✔
Propargyl alcohol			✔
Crystalline silica quartz		✔	✔
Ethylbenzene			✔
Ammonium Chloride		✔	✔
Hydrofluoric acid			✔
2-Butoxyethanol (Ethylene glycol butyl ether)			✔
Acetic Acid		✔	
Methanol	✔		
Phosphoric acid, calcium salt (2:3)			✔

6.3.2.3. Hazard Summary of Air Pollutants that are Related to Well Stimulation Fluid

There are fifteen chemicals listed in Tables 6.C.1– 6.C.4 for hydraulic fracturing and acidization activity that are also listed on the California Air Resources Board (CARB) Toxic Air Contaminant (TAC) Identification List (CARB, 2015). These compounds are listed in Table 6.3-7, along with an indication of the well stimulation activity that they are reportedly used in. Five of the compounds listed on the TACs list are already identified in the previous tables, but all compounds listed as TACs should be considered hazardous and included in subsequent risk assessments. The California TACs list (CARB, 2015) includes all Hazardous Air Pollutants (HAPs) listed by the U.S. EPA and are heavily regulated compounds.

Table 6.3-7. The substances used in hydraulic fracturing and acidization that are also listed on the California TAC Identification List (http://www.arb.ca.gov/toxics/id/taclist.htm).

Chemical Name	CASRN	Used in Hydraulic Fracturing	Used in Acidization
Hydrochloric acid	7647-01-0	✔	✔
Methanol	67-56-1	✔	✔
Toluene	108-88-3		✔
Acetophenone	98-86-2		✔
Ethylene Glycol	107-21-1	✔	✔
Formaldehyde	50-00-0	✔	✔
Naphthalene	91-20-3	✔	✔
Diethanolamine	111-42-2	✔	
Benzyl Chloride	100-44-7	✔	
Acrylamide	79-06-1	✔	

Volume III, Chapter 3 summarizes a list of all CARB-reported TACs air emissions associated with all oil-well production activities including well stimulation fluids (Chapter 3, Section 3.3.2.2). We noted that not all of the TACs listed above are reported emissions—likely as a result of different requirements for reported use versus reported emissions. It is not possible at this point to allocate the CARB-reported emissions specifically to the use well stimulation fluids. In addition to chemicals added to well stimulation fluids, there a number of TACs released during well stimulation activities that are not added directly to the well. As TACs, these substances have all been identified as posing human health hazards, with the actual health risk dependent on the magnitude and duration of exposure. Among this substance list are combustion products and/or chemical emissions from pumps, generators, compressors, and equipment; venting and flaring; dust from well stimulation activity; leaks from transfer lines and/or well heads; and emissions related to leakage of oil and gas from stimulated wells (this category does not include emissions from refining and use of the hydrocarbon products). A variety of mobile sources relevant to oil and gas (and presumably to well stimulation) activities are tracked by CARB in its emissions inventories (See Chapter 3, Section 3.3.2.2), especially for off-road diesel equipment. However, it is not clear how to apportion these activities between conventional oil production and well stimulation activities without a much more detailed study.

Several criteria pollutants (particulate matter, carbon monoxide, nitrogen oxides, and sulfur dioxide) as well as reactive organic gases are associated with well stimulation activities (see Section 3.3.2.2 for details on emissions estimates). Criteria pollutants are heavily regulated and should be included in any hazard or risk assessment associated with well stimulation. Given the known and accepted hazards associated with criteria pollutants, no further hazard assessment is provided for these compounds in this chapter.

6.3.3. Literature Summary of Human Health Hazards Specific to Well Stimulation

In the sections above, we made bottom-up characterizations and rankings of chemicals used and/or emitted during well stimulation operations in California. This section reviews and analyzes the chemical hazards of well stimulation chemicals based primarily on published source categories related to well stimulation activities and associated equipment. Much of the literature discussed below is associated with activities outside of California, but offers insights on what is or could be done in California.

Colborn et al. (2011) used Chemical Abstract Service (CAS) numbers and systematic searches in the National Library of Medicine, Toxicology Data Network (TOXNET) and other databases to determine that (a) 75% of the identified compounds from fracturing fluids in samples from Colorado are known to negatively impact sensory organs, the gastrointestinal system, and/or the liver; (b) 52% of the identified chemicals have the potential to adversely affect the nervous system; and (c) 37% are candidate endocrine disrupting chemicals (EDCs). EDCs present unique hazards compared to other toxins, because their effects at higher doses do not always predict their effects at lower doses (Vandenberg et al., 2012). They are particularly hazardous during fetal and early childhood growth and development (Diamanti-Kandarakis et al., 2009), can impact the reproductive system, and have epigenetic mechanisms that may lead to pathology decades after exposure (Zoeller et al., 2012).

In addition to the chemicals used in well stimulation, the major constituents of well acidization fluid are hydrochloric acid and hydrofluoric acid. Hydrochloric acid is used frequently in oil and gas wells in California and elsewhere as an additive to well-injection fluids during matrix acidizing, wellbore cleanout, and other forms of acid treatments of oil and gas wells (Colborn et al., 2011; Stringfellow et al., 2014) (also see Volume I for more details). Hydrochloric acid is corrosive to the skin, eyes, and mucous membranes, and is associated with a number of acute health effects (ATSDR, 2002). Oral exposure may result in the corrosion of mucous membranes, the esophagus, and the stomach. Symptoms may include nausea, vomiting, and diarrhea (U.S. EPA, 2000a). Dermal exposure may result in severe burns, ulceration, and scarring. Chronic exposures in occupational settings are associated with gastritis, chronic bronchitis, dermatitis, and photosensitization (U.S. EPA, 2000a). As discussed in the occupational health section below, we note that exposure to acid vapors resulting in acid-vapor inhalation is a hazard for any unprotected individuals close to the location of acid use or transfer.

Hydrofluoric acid is also used as an additive to well injection during matrix acidizing, wellbore cleanout, and other forms of acid treatments of oil and gas wells (Colborn et al., 2011; Stringfellow et al., 2014) (See Volume I). Acute exposure to hydrofluoric acid in liquid and gaseous form causes irritation of the eyes and nose, and can result in severe respiratory damage (Centers for Disease Control and Prevention (CDC), 2014). In high doses, exposure to hydrofluoric acid can lead to convulsions, cardiac arrhythmias, or death from cardiac or respiratory failure (U.S. EPA, 2000b). Chronic exposure to

elevated concentrations of hydrofluoric acid is associated with adverse pulmonary effects, renal injury, thyroid injury, anemia, hypersensitivity, and dermatological reactions (U.S. EPA, 2000b). When inhaled at low concentrations, hydrofluoric acid can result in nose, throat, and bronchial irritation and congestion (ATSDR, 1993; CDC, 2014). To date, no studies on the public health dimensions of hydrofluoric and hydrochloric acid have been conducted in the upstream oil and gas context.

6.4. Water Contamination Hazards and Potential Human Exposures

This section reviews the transport mechanisms that could cause human exposures to stimulation chemicals through water contamination. Section 6.4.1 briefly reviews the pathways identified in Volume II, Chapter 2, and summarized in Table 6.2-1, and discusses implications for human health. This is followed by Section 6.4.2, which provides a literature survey of health issues attributed to water contamination due to stimulation.

A direct impact of concern from chemical use for well stimulation is the potential for water contamination and subsequent human exposure from accidental releases related to the handling of the well stimulation fluids and the management of produced water that may contain stimulation chemicals. Similarly, potential subsurface leakage pathways into protected groundwater present a potential impact of contamination by the petroleum constituents in the reservoir. This risk may be exacerbated by the presence of chemicals used in hydraulic fracturing. If chemicals contained in well stimulation fluids are well managed and not released into usable water, including agricultural water, then the public health risks would be reduced. Acid use increases the probability that naturally occurring heavy metals and other pollutants from the oil-bearing formation will be dissolved and mobilized. Assessment of the environmental public health risks posed by acid use along with commonly associated chemicals, such as corrosion inhibitors, cannot be undertaken without a more complete disclosure of chemical use, and a better understanding of the chemistry of treatment fluids and produced water returning to the surface, in order to understand the risks these fluids may pose. Risk assessment would also require better knowledge of potential transport mechanisms and pathways that could lead to human exposure, as well as how treatment chemicals are altered during transport.

6.4.1. Summary of Risk Issues Related to Water Contamination Pathways

The potential for surface and groundwater contamination from well stimulation activities (contamination with stimulation chemicals, recovered fluids and produced water, residual oil, methane and other compounds) was evaluated in great detail in Chapter 2 of this volume. Release mechanisms and environmental transport pathways associated with well stimulation and production that are relevant to California include spills and leaks, percolation of wastewater from unlined pits, siting of disposal wells near abandoned wells or into protected groundwater, reuse or disposal of inadequately treated wastewater; loss of wellbore integrity; subsurface leakage and migration through abandoned wells, migration though faults, fractures, or permeable regions, and illegal waste discharge

(Section 2.6.2). Some of these release mechanisms are primarily relevant to California, and are uncommon elsewhere, such as disposal of wastewater in unlined percolation pits, which has been banned in many states, and potential siting of disposal wells into protected groundwater. However, many of the release mechanisms have also been noted in other parts of the country. Below, we briefly summarize the main findings from Chapter 2 with regard to release mechanisms and transport pathways of concern for human health impacts.

Stimulation fluids can move through the environment and come into contact with human populations in a number of ways, including surface spills, accidental releases (Rozell and Reaven, 2012), loss of zonal isolation in wellbores (Chilingar and Endres, 2005; Darrah et al., 2014), venting and flaring of gases (Roy et al., 2013; Warneke et al., 2014), and transportation and disposal of wastes (Rozell and Reaven, 2012; Warner et al., 2012; Warner et al., 2013a; Fontenot et al., 2013).

6.4.1.1. Disposal of Produced Water in Unlined Pits

As noted in Volume II, Chapter 2, the most commonly reported recovered fluids and produced water disposal method for stimulated wells in California is by evaporation and percolation in unlined surface impoundments, also referred to as unlined sumps or pits. Operators report that nearly 60% of the produced water from stimulated wells was disposed of in unlined sumps during the first full month after stimulation. There is no testing required, or thresholds specified, for the contaminants found in well stimulation fluids or other naturally occurring chemical constituents in produced water, such as benzene, heavy metals, and naturally occurring radioactive materials (NORMs). The primary intent of unlined pits is to percolate water into the ground, and as a result, this practice provides a potentially direct subsurface pathway for the transport of produced water constituents, including returned stimulation fluids, into groundwater aquifers that are or may be used for human consumption and agricultural use. Where groundwater intercepts rivers and streams, surface water resources could also be affected. If protected water were contaminated and if plants (including food crops), humans, fish, and wildlife use this water, it could introduce contaminants into the food web and expose human populations to known and potentially unknown toxic substances.

6.4.1.2. Public Health Hazards of Produced Water Use for Irrigation of Agriculture

As noted in Volume II, Chapter 2, large volumes of water of various salinities and qualities are produced along with oil. Most produced water is re-injected into the oil and gas reservoirs to help produce more oil, maintain reservoir pressure, and prevent subsidence. But some of this produced water is not highly saline, and small quantities of it are now being used by farmers for irrigation. As discussed in Chapter 2 of this volume, concerns arise that stimulation chemicals could be mixed with produced water and thus end up in irrigation water. Because of the growing pressures on water resources in the state, there is increasing interest in whether produced water could be used for a range of beneficial

purposes such as groundwater recharge, wildlife habitat, surface waterways, irrigation, and other uses. If produced water comes from an oil field where well stimulation has been used, stimulation chemicals could also be present in the produced water and would not necessarily be detected by current testing. The presence of stimulation chemicals and other naturally occurring constituents, such as heavy metals that could be mobilized by stimulation chemicals makes it far more difficult to determine if the produced water can be safely reused. The presence of stimulation chemicals also makes it more difficult to determine the amount and type of water treatment required to make the water safe for beneficial use in agriculture from a public health perspective.

6.4.1.3. Public Health Hazards of Shallow Hydraulic Fracturing

Deep fracturing operations are unlikely to produce fractures and conduits that intersect fresh water aquifers far above them (See Volume I of this study for more details). However, in California, about three quarters of the hydraulic fracturing takes place in shallow wells less than 600 m deep. Where drinking water aquifers exist above shallow fracturing operations, there is an inherent risk that hydraulic fractures could intersect aquifers used for drinking, agriculture, and other uses and contaminate them, thus introducing human exposure pathways and public health risks. To the extent that human populations are drinking, washing, or using water that has been contaminated via this environmental exposure pathway, there exists a public health risk (See Chapter 2 of this volume for me details water exposure pathways).

6.4.1.4. Leakage Through Wells

One of the problems faced in a number of other states is oil and gas development in regions that have not previously had intensive oil and gas development. California's experience with well stimulation is the opposite: most well stimulation is occurring in reservoirs where oil and gas has been produced for a long time. This means the operations are taking place where many wells have previously been drilled, plugged, abandoned, and orphaned. Leakage can occur if a hydraulic fracture intersects another well (offset well). Offset wells can also act as a conduit through which emissions to air and water resources can occur. If protected water is contaminated and if plants (including food crops), humans, fish, and wildlife use this water, it could introduce contaminants into the food web and expose human populations to known and potentially unknown toxic substances. Because geologic conditions in California result in almost no coal mining, we did not consider leakage facilitated by abandoned coal mines, which is a problem in other states.

6.4.1.5. Injection Into Usable Aquifers

In June 2014, the U.S. EPA expressed concerns to the state of California regarding an EPA evaluation of injection wells in California used to dispose of oil-field waste, primarily recovered fluids and produced water that returns to the wellhead along with oil (U.S. EPA, 2014c). The EPA found that some wells inappropriately allowed injection of waste

into protected groundwater. The California Division of Oil, Gas and Geothermal Resources (DOGGR) has shut down some of these wells and is reviewing many more for possible violations. Some chemicals that are used in well-stimulation operations are known to be toxic, but more than 50% of reported well stimulation chemicals in California have unknown environmental and health profiles. Some of the naturally occurring constituents in produced water are also toxic. Introduction of recovered fluids or produced water into protected groundwater presents a risk to the health of human populations that may drink, bathe, or irrigate with these water supplies.

6.4.2. Literature on Water Contamination from Well Stimulation

6.4.2.1. Exposure to Water Pollutants

We identified original research, including modeling studies on the potential for exposures to water quality impairment associated with oil and gas development enabled by well stimulation. We excluded studies that explored only evaluative methodology or baseline assessments, as well as papers that simply comment on or review previous studies. Papers on the potential for exposure to well-stimulation-associated contaminated water (a) rely on empirical field measurements, (b) explore plausibility of mechanisms for contamination, or (c) use modeled data to determine hazard and risk associated with potential water exposure pathways. Some of these studies explore only one aspect of shale gas development, such as the well-stimulation process of hydraulic fracturing. These studies do not indicate whether well-stimulation-enabled oil and gas development as a whole is associated with water contamination and are therefore limited in their utility for gauging water quality impacts. We are only concerned with actual findings in the field or modeling studies that specifically identify hazard, or actually document the occurrence or non-occurrence of water contamination.

Surface and groundwater contamination from well-stimulation-enabled oil and gas development is extensively documented in Chapter 2 of this volume. But the question of potential health risks remains, especially given the dearth of investigations and monitoring on this issue in California. Some association studies have reported that well stimulation contributes to higher levels of methane in drinking-water wells within 1 km of active gas development sites (Darrah et al., 2014; Jackson et al., 2013; Osbourne et al., 2012). Other studies found no association and have suggested that methane contamination of shallow groundwater from oil and gas production may be less likely to occur in certain shale formations, owing in part to regional geological variations, including the presence of intermediate gas-bearing formations above target formations (e.g., in the Pennsylvania area of the Marcellus Shale region), but not others (e.g., in the Fayetteville shale region) (Warner et al., 2013b). The most recent study on fugitive gas contamination of drinking-water wells used noble gas data to implicate faulty well production casings in water contamination rather than upward migration of methane through geological strata triggered by hydraulic fracturing (Darrah et al., 2014). While methane is not considered to be toxic, these studies suggest that there are subsurface pathways through which

gases and liquids, some of which may contain hazardous compounds, may be present. Methane—particularly thermogenic methane (Stolper et al., 2014)—can migrate and mix with protected water through natural seepages (Dusseault et al., 2014; Dusseault and Jackson, 2014). Such seepages are common in California. Investigations of aquifer contamination attributable to oil and gas development have not been conducted in California. There is a need for these investigations, including studies to determine the effect of natural seepages in methane migration.

Other studies that evaluated water quality in private drinking-water wells near natural gas operations found higher levels of arsenic, selenium, strontium, and total dissolved solids in water wells located within 3 km of active gas wells (Fontenot et al., 2013). While this study used historical data from the region as a baseline to link the water contamination to natural gas development, the specific mechanism responsible for contamination was not determined.

Water contamination events associated with well stimulation have been documented in geographically diverse parts of the country. In Colorado, an analysis of 77 reported surface spills (~0.5% of active wells) within Weld County and groundwater monitoring data revealed BTEX (benzene, toluene, ethylbenzene, xylene) contamination in groundwater (Gross et al., 2013). Another study in Colorado measured estrogen and androgen receptor activity in surface and groundwater samples, using reporter gene assays in human cell lines from drilling-dense areas in the Piceance basin (Kassotis et al., 2013). Water samples collected from the more intensive areas of natural gas extraction exhibited statistically significantly more estrogenic, antiestrogenic, or antiandrogenic activity than reference sites. Notably, the concentrations of chemicals detected by Kassotis and colleagues (2013) were high enough to potentially interfere with the response of human cells to male sex hormones and estrogen.

In August 2014, the Pennsylvania Department of Environmental Protection (PA DEP) announced that 243 cases of water contamination attributable to oil and gas development in the region had occurred since 2008, and as of 4 March 2015, the number of confirmed water contamination cases was 254 (PA DEP, 2014). While this database makes clear that these cases of water contamination were caused by oil and gas development, it is not clear which mechanisms were most prominent. However, the presence of methane and other VOCs in the aquifers suggests that loss of wellbore integrity was a likely mechanism among the many of the cases. The majority of the events occurred in the northeastern region of the state; however, reasons for this geographic trend are still unknown and are currently being investigated. More research is needed to determine if wellbore integrity is associated with these events and if that integrity is affected by hydraulic fracturing.

6.4.2.2. Oil and Gas Recovered and Produced Water

Well stimulation generates recovered fluids and produced water. Evidence indicates that approximately 35% of the initial fracturing fluid volume injected underground returns to the surface as recovered fluids and produced waters, although estimates range from 9% to

80% (U.S. EPA, 2004, 2010; Horn, 2009). Recovered fluids and produced water contain chemical compounds added to fracturing fluids as well as naturally occurring compounds that are mobilized from target geological features (Alley et al., 2011; Thurman et al., 2014; Warner, 2013a). Compounds hazardous to human health identified in produced waters include chlorides, heavy metals, and metalloids (e.g., cadmium, lead, arsenic), volatile organics (e.g., benzene, toluene, ethylbenzene, and xylene), bromide, barium, and, depending upon the geochemistry of the target reservoir, naturally occurring radioactive materials (e.g., radium-226 and radon) and other compounds (Alley et al., 2011; Maguire-Boyle and Barron, 2014; Nelson et al., 2014). Many of these naturally occurring compounds have moderate to high toxicity and can induce health effects when exposure is sufficiently elevated (Balaba and Smart, 2012; Haluszczak et al., 2013). It should be noted that no studies to date have analyzed the chemical constituents of recovered fluids and produced water from well-stimulation-enabled oil wells in California.

Recovered fluid and produced water are sometimes treated at publicly owned treatment works (POTWs) and then discharged into surface waters (Ferrar et al., 2013). This practice is currently applied to a subset of recovered fluid/produced water in California (DOGGR, 2014) (also see Chapter 2 on impacts to water resources). Warner et al. (2013a) examined water quality and isotopic compositions of discharged effluents, surface waters, and stream sediments associated with a Marcellus wastewater treatment facility site. This study reported that treated recovered fluid and produced water still contained some elevated concentrations of contaminants associated with shale gas development. The researchers also found elevated levels of chloride and bromide downstream, along with radium-226 levels in stream sediments at the point of discharge that were approximately 200 times greater than upstream and in background sediments, and well above regulatory standards (Warner et al., 2013a). The study did not differentiate what amounts of these elevated concentrations were directly attributable to hydraulic fracturing. Some papers have noted that these types of emissions to water supplies could increase the health risks of residents who rely on these surface and hydrologically contiguous groundwater sources for drinking, bathing, recreation (Wilson and VanBriesen, 2012), and sources of food (i.e., fish protein) (Papoulias and Velasco, 2013).

6.5. Air Emissions Hazards and Potential Human Exposures

In addition to the potential direct impacts of water contamination, there is the possibility of direct public health risks of exposures to stimulation chemicals that are known toxic air contaminants (TACs). In Volume II Chapter 3, we analyzed the SCAQMD mandatory oil and gas reporting database and noted TACs have been reported as used in hydraulic fracturing and acidizing fluids. All of these TACs are hazardous to human health, yet none of them have known emission factors. This makes it difficult to assess the extent to which populations may be exposed and at what concentrations. Section 6.5 below expands this topic. This section reviews the potential human health impact of air emissions associated with well stimulation in two parts. Section 6.5.1 reviews what is known about air emissions from the assessment in Chapter 3 and elsewhere. Section 6.5.2 reviews the literature on human health impacts.

6.5.1. Emissions Characterized in Chapter 3

As discussed in Chapter 3 of this volume, air emissions from oil and gas development can come from a variety of sources, including, but not limited to drilling, production processing, well completions, servicing, and transportation. Among *known* air contaminants, compounds of particular concern that are known to be emitted during the well-stimulation-enabled oil and gas development process (and from oil and gas development in general) are BTEX compounds (benzene, toluene, ethylbenzene, and xylene), formaldehyde; hydrogen sulfide; particulate matter (PM); nitrogen oxides (NO_x); sulfur dioxide (SO_2); polycyclic aromatic, aliphatic, and aromatic hydrocarbons; and volatile organic compounds (VOCs) that can contribute to tropospheric ozone formation.

Also discussed in Chapter 3 of this volume are methane emissions, which are currently assessed as greenhouse gases but can also be used as a predictor of many VOC emissions. Some VOCs are directly health damaging (e.g., benzene), and many others are precursors to regional tropospheric ozone, a strong respiratory irritant. In the San Joaquin Valley Unified Air Pollution Control District (APCD), 2012 oil and gas associated reactive organic gas (ROG) emissions were approximately 8% of total regional ROG emissions (see Chapter 3). In a field-based study in the San Joaquin Valley of California, Gentner et al. (2014) found that at least 22% of all anthropogenic VOC emissions are attributable to oil development.

The quantity of specific chemicals emitted to the atmosphere per unit of injected well stimulation fluid is completely lacking from the existing literature. Compounds noted in the previous paragraph can be emitted or released prior to use during transport, transfer, blending, and injection by accidental release, intentional release or by fugitive emission pathways. After injection of fluid into the well-bore, the release pathways and emission rates become even more uncertain, because of a lack of knowledge about the recovered fraction of well stimulation fluid and changes in composition of recovered fluid and produced water at stimulated wells. There are a number of potential release pathways to air for the stimulation fluids recovered from a treated well, including both intentional (evaporation ponds, agricultural use, re-injection) and accidental (spills, transportation, disposal and fugitive emissions). None of these potential emission pathways for down-hole TACs is sufficiently characterized beyond the frequency and total mass estimates derived in Chapter 2.

Emission rates for TACs that are indirectly related to well stimulation activity are based on activity-specific emission factors that report the quantity of a pollutant released to the atmosphere relative to an activity associated with the release of that pollutant. Emission factors are provided by regulatory agencies such as the U.S. EPA. Generic or generalizable emission rates are not available at the wellhead scale. Estimating emission rates depends on the combination of site-specific activities and equipment (e.g., number of stationary and mobile source, leakiness of transfer lines and connections). However, all TACs by

definition are hazardous, so they should be included in any thorough risk assessment for well stimulation activity using case-specific conditions and emission factors to determine ultimate exposures and quantify risk.

6.5.2. Potential Health-Relevant Exposure Pathways Identified in the Current Literature

6.5.2.1. Air Emissions Exposure Potential

Based on the potential harm of a number of VOCs (i.e., benzene, toluene, ethylbenzene, xylene, etc.) and the role of VOCs in the production of tropospheric ozone, we considered studies that address methane *and* non-methane volatile organic compounds (VOC) emissions. We considered papers that specifically address human exposures from well stimulation (i.e., unconventional oil and gas development) at either a local or regional scale. These include local and regional measurements of non-methane volatile organic compounds and tropospheric ozone.

As discussed in Chapter 3 of this volume, emissions from oil and gas development can come from a variety of sources including, but not limited to, drilling, processing, well completions, servicing, and transportation. Of particular concern are BTEX compounds (benzene, toluene, ethylbenzene, and xylene), other VOCs; formaldehyde; hydrogen sulfide; methylene chloride; particulate matter (PM); nitrogen oxides (NO_x); sulfur dioxide (SO_x); polyaromatic, aliphatic, and aromatic hydrocarbons; and tropospheric ozone.

An issue of potential concern in California is tropospheric (ground-level) ozone, which is formed through the interaction of VOCs, and NO_x in the presence of sunlight (Jerrett et al., 2009; U.S. EPA, 2013). Tropospheric ozone is a strong respiratory irritant associated with increased respiratory and cardiovascular morbidity and mortality (Jerrett et al., 2009; UNEP, 2011). However, as noted in Chapter 3 of this volume, the oil and gas industry is currently not a major contributor to tropospheric precursors in California air basis. There is some research on tropospheric ozone production associated with oil and gas development operations in other states. Modeling studies in the Haynesville and Barnett shale plays have predicted substantially increased atmospheric ozone concentrations associated with oil and gas development in Texas (Kemball-Cook et al., 2010; Olaguer, 2012; Gilman et al., 2013). Some observations in oil and gas producing basins in the western U.S. have found high levels of ozone in the winter, often in excess of air quality standards (Edwards et al., 2014). Nevertheless, as discussed in Volume II Chapter 3 and in contrast to the studies noted above, the ozone levels in California air basins are mostly dependent on an abundance of ozone precursors from outside of oil production.

As discussed in Chapter 3 of this volume, methane emissions, which are currently assessed as greenhouse gases, can be used as a predictor of many VOC emissions. Some VOCs are directly health damaging (e.g., benzene), and many others are precursors to regional tropospheric ozone. In a field-based study in the San Joaquin Valley of California, Gentner et al. (2014) found that at least 22% of all anthropogenic VOC emissions are attributable to oil development.

Local human exposures to emissions from oil and gas development have not been well-characterized, but modeling and preliminary studies have indicated that intermittent spikes in emissions to the atmosphere may pose increased risks to local human populations through air pollution concentrations at the regional scale (Brown et al., 2014; Colborn et al., 2014). Few studies to date have investigated the frequency and magnitude of air pollution emission spikes from oil and gas development, but available studies document their occurrence and their potential frequency and magnitude (Allen et al., 2013; Macey et al., 2014; Helmig et al. 2014).

6.5.2.2. Emissions and Potential Exposures from Equipment and Infrastructure

Oil and gas development relies on a variety of ancillary infrastructure throughout the well stimulation and oil and gas production process. This equipment includes, but is not limited to, diesel-powered trucks, generators, and pumps, separator tanks, condensate tanks, pipelines, flaring/venting operations, and gas compressor stations. The deployment and use of each of these pieces of equipment act as emissions sources that can present risks through exposure to chemicals, air emissions, and physical stressors. Specific to well stimulation operations is the need for heavy truck traffic to transport water, proppant, chemicals, and equipment to and from the well pad. Well stimulation as practiced in California typically requires about a hundred to two hundred heavy truck trips per vertical well, and two hundred to four hundred trips per horizontal well, counting two trips for each truck traveling to the site. This is one-third to three-quarters of the heavy truck traffic required for well pad construction and drilling.

The pollutants of primary health concern identified in the scientific literature and attributable to transportation and other heavy machinery associated with well stimulation are emissions of dust, diesel particular matter (dPM), nitrogen oxides (NO_x), sulfur dioxide and secondary sulfate particles (SO_x), volatile organic compounds (VOCs), and secondarily tropospheric ozone (Roy et al., 2013; Kemball-Cook et al., 2010). A pollutant of primary health concern emitted from the transportation component of shale gas development is dPM with aerodynamic diameter less than 2.5 microns ($PM_{2.5}$). dPM is a California TAC and a well-studied health-damaging pollutant that contributes to cardiovascular illnesses, respiratory diseases (e.g., lung cancer) (Garshick et al., 2008), atherosclerosis, and premature death (Pope, 2002; Pope et al., 2004). A study by the California Air Resources Board indicates that for each 10 $\mu g/m^3$ increase in $PM_{2.5}$ exposure in California, there is an expected 10% (uncertainty interval: 3%, 20%) increase in the number of premature deaths (Tran et al., 2008). Particulate matter can also contain concentrated associated products of incomplete combustion (PICs), and when particle diameter is < 2.5 μm, they can act as a delivery system of these compounds to the alveoli of the human lung (Smith et al., 2009). In addition to dPM, NO_x and VOCs, other pollutants prevalent in diesel emissions react in the presence of sunlight and high day-time temperatures to produce tropospheric (ground-level) ozone. Tropospheric ozone is a well-established respiratory irritant associated with increased respiratory and cardiovascular morbidity and mortality (Jerrett et al., 2009). It should be noted that most of the places

where well stimulation is known to take place in California—The San Joaquin Valley and the Los Angeles Basin—are also the regions that are consistently out of attainment for atmospheric concentrations of tropospheric ozone. As such, oil and gas developments in these regions are a potentially significant factor (Gentner et al., 2013) of cumulative environmental public health risks for populations in these areas.

Formaldehyde is a volatile compound with well-established health impacts that is produced all along the oil and gas production chain. Notably, it is formed by incomplete combustion emitted by natural gas-fired reciprocating engines at oil and gas compressor stations, as well as being a component of diesel combustion. It is a suspected human carcinogen, but it has also been associated with acute and chronic health effects (U.S. EPA, 2013). One community-based exploratory monitoring study determined that levels of formaldehyde exceeded health-based risk levels near compressor stations with gas developed from wells enabled by hydraulic fracturing in Arkansas, Pennsylvania, and Wyoming oil/gas production sites (Macey et al., 2014). It should be noted that formaldehyde is not added to stimulation fluids, but rather is a product of combustion associated with oil and gas development activity, including well stimulation activity.

6.5.3. Public Health Studies of Toxic Air Contaminants

Oil and gas development—including that enabled by well stimulation—creates the risk of exposing human populations to a broad range of toxic air contaminants (TACs). Data suggest that these TACs are likely more elevated close to compared to far from active oil and gas development, and that emissions of TACs in areas of high population density (e.g., the Los Angeles Basin) result in larger population exposures than when population density is lower (See Chapter 3 of this Volume for more details).

Many of the constituents used in and emitted by oil and gas development are known to be damaging to health, and place disproportionate risks on sensitive populations, including children, the elderly, those with pre-existing respiratory and cardiovascular conditions, and those exposed to multiple environmental stressors. Oil and gas development poses more elevated population health risks when conducted in areas of high population density, such as the Los Angeles Basin, because it results in larger population exposures to TACs (see Los Angeles Basin Case Study in Volume III for more details).

California has large developed oil reserves located in densely populated areas. For example, the Los Angeles Basin has the highest concentrations of oil in the world, but Los Angeles is also a global megacity, and oil and gas development occurs in close proximity to human populations. In the San Joaquin Valley, there are a number of communities that live, work, and play near oil and gas development. Approximately half a million people live within one mile of a stimulated well, and many more live near oil and gas development of any type. In addition, large numbers schools, elderly facilities, and daycare facilities are sited within a mile of a stimulated well. The closer citizens are to these industrial facilities, the more potentially elevated their exposure to TACs. Volume II,

Chapter 3 indicates that stationary source oil and gas facilities in the San Joaquin Valley are responsible for over 70% of H2S emissions, and 2-5.5% of benzene, formaldehyde, hexane, and xylene emissions. In the South Coast region, stationary oil and gas sources are responsible for less than 0.25% of all ten indicator TACs studied. While these fractions are in many cases not large as a fraction of regional impacts, they can still have important health impacts on nearby populations.

Studies from out of state indicate that community public health risks of exposures to toxic air contaminants, such as benzene and aliphatic hydrocarbons, are most significant within 800 meters (½ mile) from active oil and gas development (McKenzie et al., 2012). Atmospheric data on dilution of conserved TACs indicate that potentially harmful community exposures can occur out to ~3 km (almost 2 miles) from the source. There are no studies from inside California that have measured the relationship between health impacts and the distance from active oil and gas development. The Los Angeles County Department of Public Health conducted a peer-reviewed public health outcome study near the Inglewood Oil Field in Los Angeles County (Rangan and Tayour, 2011). This study did not find any health effects in populations relative to proximity to oil and gas development. However, the study was not designed to see long-term outcomes with incidence rates below ~ 1%. Therefore, significant questions remain about the health effects of proximity to oil and gas production that should be the subject of further study.

6.5.3.1. Methods for Peer Review of Scientific Literature

We conducted a review of the peer-reviewed scientific literature on the environmental public health and occupational health dimensions of well stimulation. In contrast to the bottom-up approach based on moving from hazard to exposure to outcome, most of the public health-relevant literature focuses on known links between population health risks and environmental pollution that arises from the well-stimulation-enabled oil and gas development. The best information for evaluation of the public health and occupational health impacts of oil and gas development, including that enabled by well stimulation in California, should be from verified California-specific datasets and peer-reviewed scientific studies conducted in California. However, we found California-specific information on public health risks to be extremely limited in quantity, quality, and scope. As a result, we also assessed the relevance of environmental public health-relevant studies from outside of California.

We included papers that consider the question of public health in the broad context of shale gas development. Of course, research findings in other categories such as air quality and water quality are relevant to public health, but in this subsection we only include those studies that directly consider the health of individuals and human populations. We only consider research to be original if it measures health outcomes or complaints (i.e., not health research that only attempts to determine opinion or methods for future research agendas).

We organized this literature review in a framework that tracks pathways from community health to various well stimulation types, in order to investigate what is known about any associations between sources of environmental pollution, potential exposures, and human health hazards related to well stimulation. We restricted the boundaries of our literature review to upstream oil and gas development processes prior to hydrocarbons being sent to market. We also only included physical health outcomes. Although some of the literature suggests that social, psychological, and economic impacts of well stimulation are possibly important for community health, these studies are beyond the scope of this review.

The source-to-outcome pathway is commonly used to describe associations between pollutant sources and health effects. This approach addresses in sequence the emissions, environmental concentrations of pollutants, pollutant exposure pathways (ambient air, water, etc.), and dose (e.g., micrograms of pollutant ingested, inhaled or absorbed per unit body weight per day) (Figure 6.5-1) (ATSDR, 2005). Potential sources of health-relevant environmental pollution are present throughout the well stimulation and oil and gas production process. Sources of environmental pollution include hydrocarbon production and processing activities (e.g., drilling, well stimulation, hydrocarbon processing and production, and wastewater disposal) and the transportation of water, sand, chemicals, and wastewater before, during, and after well stimulation (Shonkoff et al., 2014).

As noted above, the best information for evaluation of the public health and occupational health impacts of oil and gas development, including that enabled by well stimulation in California, should be from verified California-specific datasets and peer-reviewed scientific studies. However, we found this California-specific information to be limited in quantity, quality, and scope. With the exception of the Inglewood study (Rangan and Tayour, 2011), which had limited scope and statistical power, there have been no comprehensive health outcome studies that focus directly on the health impacts of stimulated wells. As a result, we also assessed the relevance of environmental public-health studies and experience from outside of California. Since 2007, the rapid growth of hydrocarbon development in shale and other low-permeability (aka, “tight”) formations across the U.S. has been accompanied by an increase in scientific investigations of the environmental and public health dimensions of oil and gas development, including that enabled by well stimulation, especially hydraulic fracturing. For example, approximately 70% of the peer-reviewed journal papers that are pertinent to the public health dimensions of onshore well-stimulation-enabled oil and gas development have been published between January 2009 and December 2014 (PSE Healthy Energy, 2014)[2]. This body of literature is still relatively new; many uncertainties and data gaps on the human health impacts persist on the national scale, and especially with application to California.

2. For a near-exhaustive collection of peer-reviewed scientific literature on the subject of shale gas and well-stimulation-enabled oil and gas development please see the PSE Healthy Energy Peer Reviewed Literature Database at http://psehealthyenergy.org/site/view/1180.

Some studies of well stimulation in other parts of the country, including Pennsylvania, Colorado, Utah, North Dakota, and Texas, may be relevant to California. There are notable differences between direct and indirect impacts of oil and gas development practices in California compared to those in other states, due to differences in geology, variability and tectonics, well-stimulation and drilling techniques, and oil production and transmission infrastructure, such as pipelines to transport fresh water, recovered fluids, and produced water (see Volume I).

However, in many cases, there are similarities between the *types* of hazards noted in other states and those in California, although the magnitude of risks associated with these hazards are not clear. For example, studies of oil and gas development with relevance to public health in Colorado, Utah, and Wyoming assess oil and gas development at the regional scale (Pétron et al., 2012; Pétron et al., 2014; Darrah et al., 2014; Thompson et al., 2014; Helmig et al. 2014) in the context of shale and source rock formations, but also of hydraulic-fracturing-enabled migrated oil development, much like the majority of production in California.

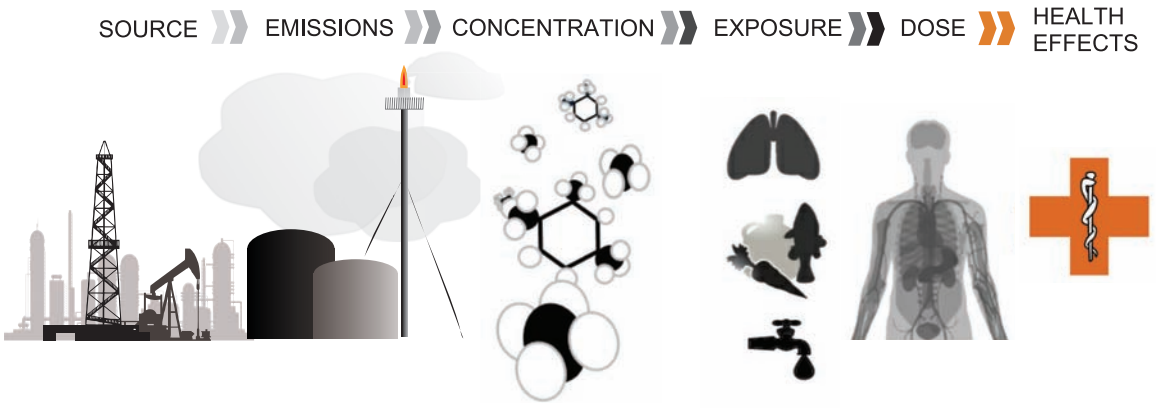


Figure 6.5-1. Simplified environmental exposure framework. Source: Shonkoff et al. (2014).

6.5.3.2. Results from the Environmental Public Health Literature Review

We divide the results for our literature review into three sections. The first section provides an overview of the peer-reviewed literature on well-stimulation-enabled shale and tight gas, and discusses the relevance of the current literature to well-stimulation-enabled oil and gas development in California. While the development of tight-gas resources is not a perfect proxy for the resources developed by means of well stimulation in California, the peer-reviewed literature between 1 January 2009 and 31 December 2014 (the time range we accessed) has a strong focus on tight-gas resources and provides useful but not necessarily relevant insight. We note, however, that there are fundamental differences between the production of tight gas and what is going on in California. Many of the volatile organic compounds found in tight gas are also produced from and emitted

by California oil and gas development, but the relative concentrations of these compounds between different types of oil and gas development can differ widely, based on geology, geography, and hydrocarbon type. In the second section, we review epidemiologic and population health studies, and identify what these studies tell us about any potential impacts on public health. The third section examines what the wider literature says about health issues due to potential exposures to water and air emissions from well-stimulation-enabled oil and gas development.

6.5.3.3. Public Health Outcome Studies

Within California, we could only identify one public health outcome study that has relevance to well-stimulation-enabled oil production. This is the Inglewood study carried out by Los Angeles County (Rangan and Tayour, 2011), which is discussed below. Outside of California, health outcome studies and epidemiologic investigations continue to be particularly limited, and most of the peer-reviewed papers to date are commentaries and reviews of the environmental literature pertinent to environmental public health risks.

A cursory public health outcome study was conducted by the Los Angeles County Department of Public Health near the Inglewood Oil Field in Los Angeles County. This study compared incidence of a variety of health endpoints including all-cause mortality, low birth weight, birth defects, and all cancer among populations nearby the Inglewood Oil Field and Los Angeles County as a whole. The study found no statistically significant difference in these endpoints between the population near the Inglewood field and the overall county population. While this may seem to indicate that there is no health impact from oil and gas development, as the study notes, the epidemiological methods employed in this study do not allow it to pick up changes in "rare events" such as cancer and birth defects in small sample sizes, as is the case in this study (Rangan and Tayour, 2011). In addition, lacking statistical power, the Inglewood Oil Field Study is a cluster investigation with exposure assigned at the group level (i.e., an ecological study). It also appears that only crude incidence ratios were calculated. This type of study design is insufficient for establishing causality and has many major limitations, including exposure misclassification and confounding, which may have obscured associations between exposure to environmental stressors from oil and gas development and health outcomes.

Health assessments have been confounded by the dearth of well-designed human-population studies that measure both human exposure and impacts. While a number of studies have found environmental and exposure pathways and health-damaging compounds in environmental concentrations sufficiently elevated to induce health effects, epidemiological studies aimed to assess and quantify the population health burden (i.e., impact severity) of oil and gas production remain in their infancy.

In a study that analyzed air samples from locations in five different states using a community-based monitoring approach, it was found that levels for eight volatile

chemicals, including benzene, formaldehyde, hexane, and hydrogen sulfide, exceeded federal guidelines (ATSDR minimal risk levels (MRLs) (ATSDR, 2014) and EPA Integrated Risk Information System (IRIS) cancer risk levels) in a number of instances (Macey et al., 2014). Notably, the residents who collected the grab samples reported a number of common health symptoms, including "headaches, dizziness or light-headedness, irritated, burning, or running nose, nausea, and sore or irritated throat" (Macey et al., 2014). We note that this was not a formal outcomes-based study, and the authors did not attempt to associate the reported health effects with the chemicals measured in the samples. But the study suggests that concentrations of hazardous air pollutants near well-stimulation-enabled oil and gas operations can be elevated to levels where health impacts could occur. We further note that such elevated levels may not be due to well stimulation itself, but to existing petroleum production combined with enhanced petroleum production.

There have been health complaints associated with oil and gas development documented in the peer-reviewed literature. These studies have limitations because they are mainly provide self-reported outcomes and are based on convenience samples, which are collected for other purposes or easily collected by or from local populations. However, many of the reported health outcomes are consistent with what would be expected from exposure to some of the known contaminants associated with oil and gas development, and are consistent across geographic space. In a 2012 survey of Pennsylvania citizens, more than half of the participants surveyed who live in close proximity to well-stimulation-enabled oil and gas development reported increased fatigue, nasal irritation, throat irritation, sinus problems, burning eyes, shortness of breath, joint pain, feeling weak and tired, severe headaches, and sleep disturbance (Steinzor et al., 2013). The survey also found that the number of reported health problems decreased with distance from facilities.

Some research has attempted to assess human-health risks related to air pollutant emissions associated with hydraulic-fracturing-enabled oil and natural gas development. Using U.S. EPA guidance to estimate chronic and subchronic non-cancer hazard indices (HIs) as well as excess lifetime cancer risks, a study in Colorado suggested that those living in closer geographical proximity to active oil and gas wells (≤ 0.8 km [0.5 mile]) were at an increased risk of acute and sub-chronic respiratory, neurological, and reproductive health effects, driven primarily by exposure to trimethyl-benzenes, xylenes, and aliphatic hydrocarbons. It also suggested that slightly elevated excess lifetime cancer risk estimates were driven by exposure to benzene and aliphatic hydrocarbons (McKenzie et al., 2012). The findings of this study are corroborated with atmospheric dilution data of conserved pollutants; for instance, a U.S. EPA report on dilution of conserved toxic air contaminants indicates that the dilution at 800 m (0.5 mile) is on the order of 0.1 mg/m^3 per g/s (U.S. EPA, 1992). Going out to 2,000 m increases this dilution to 0.015 mg/m^3per g/s, and going out to 3,000 m increases dilution to 0.007 mg/m^3per g/s. Given that, for benzene, there is increased risk at a dilution of 0.1, it is not clear that concentrations out to 2,000 m (1.25 miles) and 3,000 m (1.86 miles) can necessarily be considered as presenting acceptable risk. However, beyond 3,000 m (1.86 miles), where concentrations

fall more than two orders of magnitude via dilution relative to the ½ mile radius, there is likely to be a sufficient margin of safety. Nevertheless, these results indicated that any potentially harmful community exposures could occur at 2,000 meters (1.25 miles) and as much as almost ~3,000 meters (~2 miles) from the source. In considering these dilution assessments, we note that—based on wind, topography, and inversion layers--dilution can increase or decrease, and that increasing density of oil and gas development will require greater dilution to attain the same level of risk as lower density.

In contrast, an oil and gas industry study in Texas compared VOC concentration data from seven air monitors at six locations in the Barnett Shale with federal and state health-based air concentration values (HBACVs) to determine possible acute and chronic health effects (Bunch et al., 2014). The study found that shale gas activities did not result in community-wide exposures to concentrations of VOCs at levels that would pose a health concern. The key distinction between McKenzie et al. (2012) and Bunch et al. (2014) is that Bunch et al. (2014) used air quality data generated from monitors focused on regional atmospheric concentrations of pollutants in Texas, while McKenzie et al. (2012) included samples at the community level. Finer geographically scaled samples can often capture local atmospheric concentrations that are more relevant to human exposure (Shonkoff et al., 2014).

This geographical correlation has been observed in random sampling efforts as well. In a recent study in Pennsylvania, researchers evaluated the relationship between household proximity to natural gas wells and reported health symptoms for 492 people in 180 randomly selected homes with ground-fed wells in an area of active drilling (Rabinowitz et al., 2014). The results suggest that close proximity to gas development is associated with prevalence of dermal and respiratory health symptoms.

In addition to population health hazards in varying distances from active oil and gas development, other studies have assessed the effect of the *density* of oil and gas development on health outcomes. In a retrospective cohort study in Colorado, McKenzie et al. (2014) examined associations between maternal residential location and density of oil and gas development. The researchers found a positive dose-response association between the prevalence of some adverse birth outcomes, including congenital heart defects and possibly neural tube defects and increasing density of development (McKenzie et al., 2014). For instance, the observed risk of congenital heart defects in neonates was 30% (OR = 1.3 (95% CI: 1.2, 1.5)) greater among those born to mothers who lived in the highest density of oil and gas development (> 125 wells per mile), compared to those neonates born to mothers who lived with no oil and gas wells within a 16 km (10-mile) radius. Similarly, the data suggest that neonates born to mothers in the highest density of oil and gas development were twice as likely (OR = 2.0, 95% CI: 1.0, 3.9) to be born with neural tube defects than those born to mothers living with no wells in a 10-mile radius (McKenzie et al., 2014). The study, however, showed no positive association between the density and proximity of wells and maternal residence for oral clefts, preterm birth, or

term low birth weight. We also note that these indirect effects, by definition, cannot be directly linked to stimulation technology, but to existing and well-stimulation-enhanced petroleum production.

6.5.4. Summary of Public Health Outcome Studies

There have been few epidemiological studies that measure health effects associated with oil and gas development, whether enabled by well stimulation or not. The studies that have been published have been heavily focused on exposures to toxic air contaminants (hazardous air pollutants), while fewer studies have evaluated associations between oil and gas development and water contamination.

Each of the studies discussed above have limitations to their study designs, their geographic focus, and their statistical power to evaluate associations. These studies suggests that health concerns about oil and gas development may not be **direct** effects specific to the well stimulation process, but rather are associated with **indirect** effects of oil and gas development. For example, the studies in Colorado (McKenzie et al., 2012; McKenzie et al., 2014) found that the most likely driver of poor health outcomes were aliphatic hydrocarbons and benzene. Neither of these compounds is added to stimulation fluids, but rather are mobilized in the subsurface and co-produced (and co-emitted) with oil and gas production, processing, transmission, and consumption.

6.6. Occupational Health-Hazard Assessment Studies

Due to their proximity to hazards, workers directly involved in well stimulation processes may have exposure to chemical and physical hazards larger than those of the surrounding communities, and therefore have the greatest likelihood of any resulting acute and/or chronic health effects. The expansion of well stimulation in California has the potential to expose workers in this industry to a range of existing hazards related to oil and gas development, and additional hazards specific to well stimulation such as elevated VOC exposures during injection and flowback operations (Esswein et al., 2014) and the use of proppant, which has been noted to subject workers to elevated silica exposure (Esswein et al., 2013). Silica exposure is a major risk factor for the development of the lung disease silicosis.

An adequate understanding of occupational health hazards requires information about the quantities and composition of materials used, handling protocols, and emissions factors of operations in addition to information about the tasks, protocols, and exposure reduction control measures for activity on well pads, in and around trucks and machinery, and in other locations throughout the oil development process related to well stimulation. Employers can and often do implement comprehensive worker protection programs that substantially reduce worker exposure and likelihood of illness and injury. Employers in the oil and gas industry are required to comply with existing California occupational safety and health regulations, and follow best practices to significantly reduce and/or eliminate

illness and injury risk to their employees (California Occupational Safety and Health Act of 1973 and Title 8 of the California Code of Regulations). In following these standards and best practices in protecting workers from chemical exposures while they are involved in well stimulation operations, employers in this industry may also reduce the likelihood of chemical exposure to the surrounding community.

There is a large California workforce engaged in the oil development and production industry. We reviewed available literature and the scope of this occupation group (and the hazards they face). Although data are available on health risks faced by this work population, little data is available on the hazards directly associated with well stimulation activities.

6.6.1. Scope of Industry and Workforce in California

Employment numbers and occupations involved in well stimulation are impossible to ascertain with precision, as companies engaged in drilling and support activities in well stimulation are also involved with overall oil and gas development in California. Any workers engaged in well stimulation are typically part of the broader oil and gas well development/production industry. This is an industry where workers can be exposed to a range of hazards in addition to those directly associated with well stimulation. Table 6.6-1 provides a summary of the employment in the oil and gas extraction industry in California.

Table 6.6-1. Employment in oil and gas extraction – California 2014.

Industry Title	Establishments	Average Monthly Employment
2111111 Crude Petroleum and natural gas extraction	179	9,669
2111112 Natural Gas Liquid Extraction	10	193
213111 Drilling Oil and Gas Wells	91	3,419
213112 Support Activities, Oil/Gas Operations	240	9,162
Total	**520**	**22,443**

Source: http://www.labormarketinfo.edd.ca.gov/

A review of all data on occupational health for the oil and gas extraction industry indicates that this industry has a high rate of worker injury and death relative to other industries, but does not collect publicly available data on the fraction of oil and gas development that is enabled by well stimulation (NIOSH, 2015a; 2015b; 2015c; 2015d). According to NIOSH (2015d), the oil and gas extraction industry had an annual occupational fatality rate of 27.5 per 100,000 workers (2003-2009)—more than seven times higher than the rate for all U.S. workers. The annual occupational fatality rate is highly variable, and correlates with the level of drilling activity. For example, the numbers of fatalities increased by 23% between 2011 and 2012 to the largest number of deaths of oil and

gas workers since 2003. Appendix 6.D provides details on occupational health data we compiled for the U.S. oil and gas extraction industry. In the sections below, we summarize studies that address the direct impacts of well stimulation within the oil and gas industry. This is U.S. data, which is relevant to California operations, but not necessary fully representative of current or future California well stimulation activities.

6.6.2. Processes and Work Practices

In seeking insight on occupational hazards from well stimulation, we identified two review papers useful for describing occupational exposures in oil and gas development (Mulloy, 2013; Witter, 2014), but these papers do not include job or process descriptions. We identified two additional peer-reviewed papers describing the work processes in oil and gas extraction that evaluate occupational exposure for silica and VOCs attributable directly to well stimulation (Esswein et al., 2013; 2014). The Esswein et al. papers (2013; 2014) report results from the National Institute for Occupational Safety and Health study that collected 111 personal-breathing-zone samples at 11 sites in five states during four seasons, for investigation of crystalline silica exposure and personal and environmental measurements at six sites in two states, for investigation of chemical exposures. We found no other publicly available data sources that include job titles or work activities during oil and gas extraction or well stimulation.

In the first of these two papers, Esswein et al. (2013) describe the processes of hydraulic fracturing, in terms of the workers involved and their typical roles as:

> *At a typical site, 10 to 12 driver/operators position and set up equipment, configure and connect piping, pressure test, then operate the equipment (e.g., sand movers, blender, and chemical trucks) required for hydraulic fracturing. Other employees operate water tanks and water transport systems, and several control on-site traffic, including sand delivery trucks and other vehicles. An additional crew includes well liners (typically 3–5) who configure and assemble well casing perforation tools and operate cranes to move tools and equipment into and out of the well. … Moving proppant along transfer belts, pneumatically filling and operating sand movers, involves displacement of hundreds of thousands of pounds of sand per stage, which creates airborne dusts at the work site (Esswein et al., 2013).*

Similarly, in the second paper, Esswein et al. (2014) describe flowback operations and the associated exposures to VOCs from these operations as:

> *Typical flowback operations have two to four flowback personnel performing flowback tasks; these were the typical number of workers at each of the sites visited. Air sampling, typically collected over two days, included workers with the following job titles and descriptions:*

- *Flowback lead: recorded well pressures and temperatures, monitored separators and other equipment*
- *Flowback tech: gauged flowback tanks 1–4 times per hr., recorded volumes, assisted in tank pumping and fluid transfers to trucks*
- *Production watch lead: monitored rate and volume of natural gas and liquid hydrocarbons*
- *Production watch technician: gauged production tanks*
- *Water management operator: gauged water tanks, ran pumps*

Workers access the tanks through hatches located on the tops of tanks. Periodically, recovered liquid hydrocarbons/condensate is pumped to production tanks or to trucks, which collect and transport process fluids off the well pad; natural gas is typically piped to gas gathering operations. Tank gauging and other tasks required during flowback can present exposure risks for workers from alkane and aromatic hydrocarbons produced by the well and diluted treatment chemicals used during hydraulic fracturing (typically a combination of acid, pH adjusters, surfactant, biocides, scale and corrosion inhibitors, and, in some cases, gels, gel demulsifiers, and cross-linking agents) (Esswein et al., 2014).

6.6.3. Acid Used in Oil and Gas Wells

The oil and gas industry commonly uses strong acids along with other toxic substances, such as corrosion inhibitors, for both routine maintenance and well stimulation (see Volume I, Chapter 2 and 3 & Volume I). These acids pose occupational hazards relevant to well stimulation. Well acidizing requires the use of hydrochloric (HCl) and hydrofluoric (HF) acid. In many cases, HF is created at the oilfield by mixing hydrochloric acid with ammonium fluoride and immediately injecting the mix down the well (Collier, 2013). Creating the HF on site may be safer than offsite production, because it reduces the risk of transport accidents. In all uses of HF, there is the potential for worker exposure to acid gases. According to industry protocols, safety precautions for those on site during an acid treatment concern detection of leaks and proper handling of acid (SPE, 2015; API, 1985). As also reported in Volume II Chapter 2, due to the absence of state-wide mandatory reporting on chemical use in the oil and gas industry, it is not known how much acid is used for oil and gas development throughout California.

Well-established procedures exist for mixing and handling acids (NACE, 2007). The parent acids do not generally migrate long distances from the well, but acids formed through a complex series of reactions during acidization can migrate deeper into the formation (Weidner, 2011). If the acidization fluids are introduced into the well in the

right proportions and order, and sufficient time and conditions allowed for reactions to proceed, then the original acids are used up during the acidization process (Shuchart, 1995). The reaction of strong acids with the rock minerals, corrosion products, petroleum, and other injected chemicals can also release contaminants of concern, such as hydrogen sulfide from acid reaction with iron sulfides, that have not been characterized or quantified. These chemicals may be present in recovered fluids and produced water (NACE, 2007). We do not have data to determine how much strong acid, including hydrochloric and hydrofluoric acid, is used in oil and gas development in California. DOGGR has only recently required reporting of all acid use that will result in a better understanding in the future. Hydraulic fracturing operations have only infrequently incorporated acid use (11 voluntarily reported applications between January 2011 and May 2014). Industry has voluntarily reported approximately twenty matrix-acidizing treatments per month throughout California, but has not revealed detailed chemical information. The South Coast Air Quality District requires reporting on the use of all chemicals by the oil and gas industry. Their data suggest widespread and common use of acid for many applications in the industry.

Environmental public health exposures to strong acids are only likely to occur at the surface, given that migration of acids in the subsurface are limited by relatively rapid reactions. The most likely human exposures to strong acids are to workers. The opportunities for exposure are predominantly the following: (1) handling and mixing of acids prior to well injection, (2) during flowback following an acid treatment, and (3) during accidents and spills.

State and federal agencies regulate spills of acids and other hazardous chemicals, and existing industry standards dictate standard safety protocols for handling acids (see Section 6.6.3.4). The Office of Emergency Services (OES) between January 2009 and December 2014 reported nine spills of acid that can be attributed to oil and gas development in California. Reports indicate the spills did not involve any injuries or deaths. These acid spill reports represents less than 1% of all reported spills of any kind attributed to the oil and gas development sector in the same period, and suggest that spills of acid associated with oil and gas development are infrequent. Given the lack of Occupational Safety and Health Administration (OSHA) reporting of worker exposures to acids, to the extent that this reporting is comprehensive, it appears that industry protocols for handling acids likely are protecting workers from such acute exposures.

Chapter 2 of this volume reports chemical spills in California oil fields, including spills of hydrochloric, hydrofluoric, and sulfuric acids. Of the 31 spills reported between January 2009 and December 2014, nine were acid spills. Among these was a storage tank at a soft water treatment plant containing 20 m^3(5,500 gallons) of hydrochloric acid in the Midway-Sunset Oil Field in Kern County that ruptured violently, releasing the acid beyond a secondary containment wall. No injuries or deaths were associated with this or any other acid spill.

Work processes and health hazards associated with well stimulation are summarized in Table 6.6-2.

The physical hazard associated with a chemical used on the job is most often characterized by evaluating a standard selection of properties associated with the individual chemical or chemical mixture. These properties include inflammability, corrosivity, and reactivity.

There are a number of different systems for classifying the hazardous properties of chemicals. The American Coatings Association, Inc. developed the Hazardous Materials Identification System (HMIS) (ACS, 2015) to aid its members in the implementation of an effective Hazard Communication Program as required by law. Another system developed by the National Fire Protection Association (NFPA) is directed at communicating potential hazards during emergency situations (NFPA, 2013.) Both systems have a "0 to 4" ranking system with a chemical ranked "4" having a severe hazard, "3" representing a serious hazard, "2" representing a moderate hazard, and "1" a slight hazard. Materials ranked "0" are of minimal or no hazard for the category ranked.

All of the chemicals reportedly in well stimulation in California (see Chapter 2, Appendix 2.A, Tables 2.A-3 and 2.A-5) were evaluated for this report using both the HMIS and the NFPA systems. Approximately 20% to 30% of the additives were not categorized under either the HMIS or NFPA systems for different hazards. Overall, only approximately 5% of the well stimulation fluid additives were considered flammable or fire hazard, and only a few compounds were ranked as physical or reactivity hazards (Figure 6.6-1).

Well stimulation fluid additives categorized as severe (4) or serious hazards (3) are listed in Chapter 2, Appendix 2.A, Table 2.A-8 (Chapter 2). Since chemical hazards and fire hazards are integral to both conventional and unconventional oil and gas extraction, the well stimulation additives illustrated in Figure 6.6-1 are not likely to pose new or unusual hazards that are specific to unconventional oil and gas production. However, the additives should be considered in evaluation of occupational exposure and in assessment of the risks associated with oil and gas production.

Table 6.6-2. Work processes and health hazards associated with well stimulation.

Work processes	Health hazards	Fed OSHA Standards
Mixing and injecting of chemicals and dusts - i.e., proppants, acids, pH adjustment agents, biocides etc.	Irritation and burns to skin and eyes Acute and chronic respiratory disease (COPD, asthma, silicosis, lung cancer) Low pH recovered fluid	Hazard Communication, Safety Data Sheets - 29 CFR 1910.1200(g) Personal Protective Equipment - 29 CFR Subpart I Specifications for Accident Prevention Signs and Tags -29 CFR 1910.145 Toxic and Hazardous Substances - 29 CFR 1910 Subpart Z Hazard Communication - 29 CFR 1910.1200 Emergency Response Program to Hazardous Substance Releases - 29 CFR 1910.120(q) Medical Services and First Aid - 29 CFR 1910.151(c)
Pressure pumping	Explosions Acute and chronic inhalation exposure due to high pressure from uncontrolled releases, use of flammable fluids, gases, and materials	Personal Protective Equipment, General Requirements - 29 CFR 1910.132
Recovered fluids	Explosions Acute and chronic inhalation exposure due to high pressure from uncontrolled releases, use of flammable fluids, gases and materials	Personal Protective Equipment - 29 CFR 1910 Subpart I Portable Fire Extinguishers - 29 CFR 1910.157 Welding, Cutting, and Brazing - 29 CFR Subpart Q, 29 CFR 1910.252, General Requirements
Multiple operations: hydrogen sulfide, volatile organic compounds (VOCs), combustion products and elevated noise	Asphyxia Nervous system, liver and kidney damage Cancer (blood)	Respiratory Protection, General Requirements - 29 CFR 1910.134(d)(iii) Air contaminants - 29 CFR 1910.1000
Transport, Rig-Up, and Rig-Down	Injuries and fatalities (struck-by, caught-in, crushing hazards, and musculoskeletal injuries) from off-site and on-site vehicle and machinery traffic or movement; heavy equipment, mechanical material handling, manual lifting, and ergonomic hazards (these are mostly indirect hazards with respect to well stimulation)	Electrical - 29 CFR 1910.307 – Hazardous (Classified) Locations Powered Industrial Trucks - 29 CFR 1910.178 Crawler, Locomotive, and Truck Cranes - 29 CFR 1910.180 Slings - 29 CFR 1910.184(c)(9) Walking-Working Surfaces - 29 CFR 1910 Subpart D Permit-Required Confined Spaces - 29 CFR 1910.146 Occupational Noise Exposure - 29 CFR 1910.95 Electrical: Selection and Use of Work Practices - 29 CFR 1910.33

Source: Adapted from U.S. OSHA (2014) and Esswein et al. (2013; 2014)

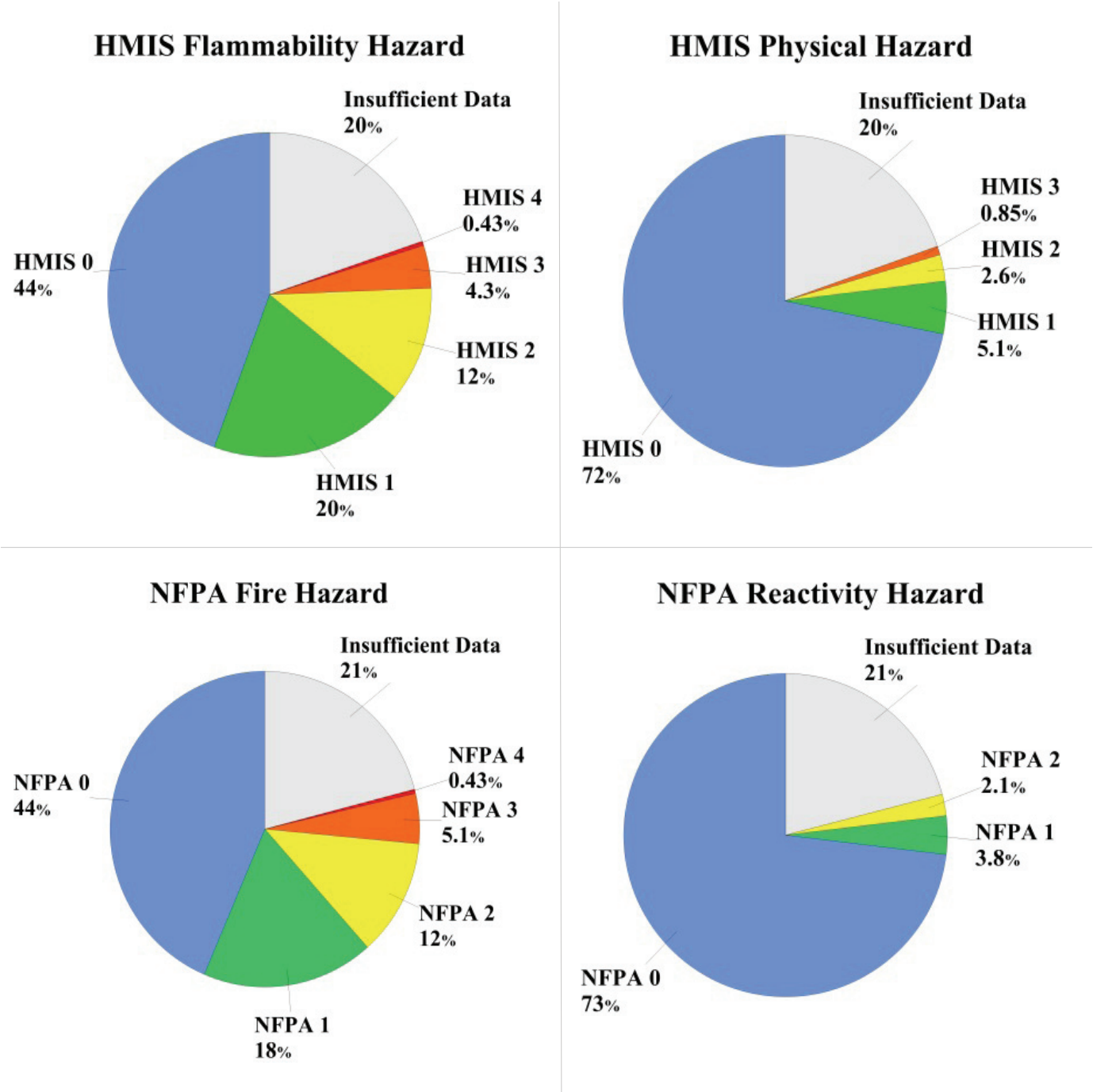


Figure 6.6-1. Evaluation of the flammability, reactivity, and physical hazards of chemical additives reported for hydraulic fracturing in California using the Hazardous Materials Identification System (HMIS) and the National Fire Protection Association (NFPA) classification system.

6.6.3.1. Occupational Health Outcomes Associated With Well Stimulation-Enabled Oil and Gas Development

There are few peer-reviewed health outcomes studies among workers in the oil and gas development industry that are specific to well-stimulation-enabled oil and gas development. For well stimulation, there are effectively no health outcome studies and only two studies addressing health risks (Esswein et al., 2013; 2014). The results of these two studies are summarized above.

6.6.3.2. Worker Protection Standards, Enforcement, and Guidelines for Well Stimulation Activities

The U.S. Occupational Safety and Health Administration (OSHA) has identified multiple hazards and enforces numerous standards for oil and gas extraction (OSHA, 2015a; 2015b). There are several specific OSHA exemptions for the oil and gas development industry, including:

- Process safety management (PSM) of highly hazardous and explosive chemicals (29 CFR 1910.119). The PSM standard requires affected facilities to implement a systematic program to identify, evaluate, prevent, and respond to releases of hazardous chemicals in the workplace. The PSM standard exempts oil and gas well drilling and servicing operations (OSHA, 2015c)

- Comprehensive General Industry Benzene Standard (29 CFR 1910.1028). Under the Comprehensive Standard, the limit for workers' exposure is 1 part per million (ppm)—the occupational exposure limit is the same. The exemption allows worker exposures up to 10 ppm in oil and gas. The exemption also eliminates requirements for medical monitoring, exposure assessments, and training (OSHA, 2015d).

- Hearing Conservation Standard (29 CFR 1910.95). This standard, designed to protect general industry employees, establishes permissible noise exposure limits and outlines requirements for controls, hearing protection, training, and annual audiograms for workers. Many sections of the standard do not apply to employers engaged in oil and gas well drilling and servicing operations (OSHA, 2015e).

- Control of Hazardous Energy Sources, or "Lockout/Tagout" (29 CFR 1910.147). The standard requires specific practices and procedures to safeguard employees from the unexpected energization or startup of machinery and equipment, or the release of hazardous energy during service or maintenance activities. The standard does not cover the oil and gas well drilling and servicing industry (OSHA, 2015f).

The U.S. OSHA has issued an alert on the hazards of silica exposure (OSHA, 2015g) and guidance to employers on other safety and health hazards during hydraulic fracturing and fluid recovery (OSHA, 2015h). The National Institute for Occupational Safety and

Health (NIOSH) has identified exposure to silica dust and volatile organic compounds as significant health hazards during oil and gas extraction (NIOSH, 2015a; 2015b; 2015c), and recommends additional quantification of exposure to diesel particulate and exhaust gases from equipment, high or low temperature extremes, noise, hydrocarbons, hydrogen sulfide, heavy metal exposure, and naturally occurring radioactive material (NIOSH, 2015d).

The California Division of Occupational Safety and Health (CalOSHA) has specific enforceable regulations pertaining to petroleum drilling and production (CalOSHA, 2015a; 2015b). For the ten-year period January 1, 2004–December 31, 2013, there were 281 inspections in oil and gas extraction: 77 inspections in NAICS 211, 98 inspections in NAICS 213111, and 106 inspections in NAICS 213112 (OSHA, 2015i). Of the 281 inspections, 153 (54%) were in response to an accident, 47 (17%) were planned, and 36 (13%) were due to complaints. Cal/OSHA is required to investigate all work-related amputations, hospitalizations for greater than 24 hours, and traumatic fatalities. There are 104 cases in which a detailed narrative is available regarding these incidents, including 16 work-related fatalities (Appendix 6.E).

The American Petroleum Institute has also published comprehensive safety and health guidelines for oil and gas well drilling and servicing operations, and includes recommended best practices from the American Conference of Governmental Industrial Hygienists and American National Standards Institute (API, 2007).

The American Petroleum Institute (API) and the Society of Petroleum Engineers have established protocols and safety precautions for those on site during an acid treatment (SPE, 2015; API, 1985). These guidelines state that (a) pressure tests with water or brine are used to ensure the absence of leaks in pressure piping, tubing, and packer; (b) anyone around acid tanks or pressure connections should wear safety goggles for eye protection; (c) those handling chemicals and valves should wear protective gauntlet-type, acid-resistant gloves; (d) water and spray washing equipment should be available at the job site; (e) when potential hydrogen sulfide gas hazards exist, workers need contained, full-face, fresh-air masks; (f) testing equipment and appropriate safety equipment should be on hand to monitor the working area and protect personnel in the area; and (g) special scrubbing equipment may be required for removal of toxic gases.

6.7. Other Hazards

Oil and gas development, including those enabled by well stimulation, creates a number of physical stressors, including noise and light pollution. Although noise pollution and light pollution are often thought of as mere nuisances, data suggest that these physical stressors can be detrimental to human health. Noise pollution is associated with truck traffic, drilling, pumps, flaring of gases, and other processes associated with well stimulation-enabled oil and gas development and oil and gas development in general.

6.7.1. Noise Pollution

While no peer-reviewed studies to date examine the public health implications of communities exposed to elevated noise from oil and gas development in California, numerous large-scale epidemiological studies have found positive associations between elevated environmental noise and adverse health outcomes. (See Noise Literature Review in Appendix 6.F.) Noise is a biological stressor that modifies the function of the human organs and nervous systems, and can contribute to the development and aggravation of medical conditions related to stress, most notably hypertension and cardiovascular diseases (Munzel et al., 2014). The World Health Organization (WHO, 2014) has noise thresholds, measured in decibels (dB), and their effect on population health, with noise levels above 55 dB considered dangerous for the general population (Table 6.7-1). A number of activities associated with drilling and production activity (Table 6.7-2), some of which could also be associated with well stimulation, generate noise levels greater than those considered dangerous to public health. Dose-response data indicate that noise during well stimulation in California and elsewhere is associated with sleep disturbance and cardiovascular disease (McCawley, 2013). These findings are corroborated by estimates from the New York State Department of Environmental Conservation on the development of shale gas (NYSDEC, 2011).

Table 6.7-1. WHO thresholds levels for effects of night noise on population health.

Average night noise level over a year $L_{night,outside}$	**Health effects observed in the population**
Up to 30 dB	Although individual sensitivities and circumstances may differ, it appears that up to this level no substantial biological effects are observed. $L_{night,outside}$ of 30 dB is equivalent to the no-observed-effect level (NOEL) for night noise.
30 to 40 dB	A number of effects on sleep are observed from this range: body movements, awakening, self-reported sleep disturbance, and arousals. The intensity of the effect depends on the nature of the source and the number of events. Vulnerable groups (for example children, the chronically ill and the elderly) are more susceptible. However, even in the worst cases the effects seem modest. $L_{night,outside}$ of 40 dB is equivalent to the lowest-observed-adverse-effect level (LOAEL) for night noise.
40 to 55 dB	Adverse health effects are observed among the exposed population. Many people have to adapt their lives to cope with the noise at night. Vulnerable groups are more severely affected.
Above 55 dB	The situation is considered increasingly dangerous for public health. Adverse health effects occur frequently, a sizeable proportion of the population is highly annoyed and sleep-disturbed. There is evidence that the risk of cardiovascular disease increases.

Source: Adapted from the WHO (2014)

Table 6.7-2. Equipment Noise Levels for Drilling and Production in Hermosa Beach, California.

Work Stage	Equipment	Sound Power Level† (dBA)
Drilling (30 month scheduled duration)	Hydraulic Power Unit	110.7
	Mud Pump	105.4
	Drill Rig	93.3
	Shaker	75.3
	Pipe Handling (Quiet Mode)	107.5
Production (at rate of 800 barrels per day)	Well Pumps	97.7
	Produced Oil Pump	77.7
	Produced Water Pump	86.7
	Shipping Pump	92.8
	Water Booster Pump	86.7
	Water Injection Pumps (2)	102.8
	Vapor Recovery Compressor	88.6
	Vapor Recovery Unit Cooler	90.2
	1st Stage Compressor (2)	96.2
	2nd Stage Compressor (2)	96.2
	Compressor Cooler	102.0
	Amine Cooler	102.1
	DEA Charge Pump	77.7
	Regenerator Reflux Pump	77.7
	Chiller	85.0
	Glycol Regenerator	92.4
	Micro-turbines (5)	92.9
	Variable Frequency Drives	83.3

Source: Adapted from Hermosa (2014) based on field measurements and identified as Source Noise Levels (measured in decibels (dBA)) used in modeling noise contour maps.

While noise mitigation measures are undertaken in some California oil fields, including Hermosa Beach (Hermosa, 2014) and Inglewood (Cardno ENTRIX, 2012), there are no data available as to their effectiveness and adherence. The City of Hermosa Beach allows noise levels in the 40-60 dB range (Appendix 6.F, Table 6.F-8a and Table 6.F-9).

6.7.2. Light Pollution

Light pollution is reported as a nuisance in communities undergoing well stimulation, because activities occur during both daytime and nighttime hours (Witter et al., 2013). While little research has been conducted on the public health implications of exposures to light pollution from oil and gas development, some epidemiologic studies of light pollution from other sources suggests a positive association between indoor artificial light

and poor health outcomes (Chepesiuk, 2009). Further, other studies suggest that night-time light exposure can disrupt circadian and neuroendocrine physiology (Chepesiuk, 2009; Davis and Mirick, 2006). Hurley et al. (2014) found that women living in areas with high levels of artificial ambient light at night may be at an increased risk of breast cancer, although how these findings translate to the levels of night-time light exposure to oil and gas development remains understudied.

6.7.3. Biological Hazards

Coccidioides immitis (*C. immitis*) is a soil fungus that causes Valley Fever and is endemic to the soils of the southwest. The San Joaquin Valley is an area where the fungal spores live in the top 2"-12" of soil. Soil disturbance associated with developing and maintaining oil field infrastructure may generate airborne *C. immitis* and expose workers and nearby residents. Cases of Valley Fever are not uncommon among workers in the oil fields of Kern County (Hirshmann, 2007).

While over 60% of people exposed to *C. immitis* never have symptoms, symptomatic infection can result in those who are exposed to the spores through inhalation. Symptoms range from mild, influenza-like illness to systemic fungal infection and severe disease, particularly in those who are immune-compromised. Coccidioidomycosis is considered an occupational hazard in endemic regions, particularly for workers who are exposed to spores through earth-moving activities or who are exposed to dusty conditions (Friedlander, 2014). In California, Cal/OSHA issued a fact sheet to employers to outline the health hazards of Valley Fever and preventative measures, focusing on worker education, adopting site plans to reduce exposure, and protecting workers against exposure with NIOSH-approved respiratory protection filters (Friedlander, 2014).

While the health hazards of Valley Fever have been outlined, no data have been published on the rates of infection among workers specifically in the oil and gas industry in California. Valley Fever remains an important occupational health hazard, as much of the well-stimulation-enabled oil and gas extraction activities take place in California's Central Valley.

6.8. Community and Occupational Health Hazard Mitigation Strategies

A number of strategies exist to reduce potential public health hazards and risks associated with well-stimulation-enabled oil and gas development activities. Most hazards have not been observed or measured in California, rendering it difficult to determine which hazards present risks at any given site in California. The most important hazards will not be identified until California-based studies document chemical compositions and release mechanisms, emission intensities, and potential for human exposure. As site-specific information becomes available, hazard mitigation strategies can be considered.

The following sections catalogue several potential community health and occupational hazard mitigation strategies. The strategies noted below highlight those among the more detailed mitigation recommendations provided above in this chapter as well as in Volume

II, Chapters 2 and 3. These strategies are to be considered in addition to employment of best practices in well-stimulation-enabled oil and gas development, which are employed to avoid exposure to a given hazard in the first place. It should be noted that mitigation and "best practices" should be systematically evaluated for effectiveness in the field, and even those mitigation practices with high efficacy are not effective if they are not properly executed and enforced.

6.8.1. Community Health Mitigation Practices

6.8.1.1. Setbacks

Exposures to environmental pollution and physical hazards such as light and noise falls off with distance from the source. The literature on oil and gas production suggests that the closer a population is to active oil and gas development, the more elevated the exposure, primarily to air pollutants but also to water pollutants, if a community relies on local aquifers for their drinking water, and zonal isolation of gases and fluids from aquifers is not achieved (see Section 6.4.1 above). While some California counties and municipalities have minimum surface setback requirements between oil and gas development and residences, schools, and other sensitive receptors, there are no such regulations at the state level. Further, the scientific literature is clear that certain sensitive and vulnerable populations (e.g., children, asthmatics, those with pre-existing cardiovascular or respiratory conditions, and populations already disproportionately exposed to elevated air pollution) are more susceptible to health effects from exposures to environmental pollutants known to be associated with oil and gas development (e.g., benzene) than others. The determination of sufficient setback distances should consider these sensitive populations.

Setback requirements have been instituted in some locales to decrease exposures to air pollutants, especially to VOCs that are known to be health damaging (e.g., benzene). The Dallas-Fort Worth area recently instituted a 460 meters (1,500 foot) minimum setback requirement between oil and gas wells and residences, schools, and other sensitive receptors. In summary, the scientific literature supports the recommendation for setbacks (City of Dallas, 2015). The distance of a setback would depend on factors such as the presence of sensitive receptors, such as schools, daycare centers, and residential elderly care facilities. The need for setbacks applies to all oil and gas wells, not just those that are stimulated.

6.8.1.2. Reduced Emission Completions and Other Air Pollutant Emission Reduction Technological Retrofits

As discussed in Volume II, Chapter 3, reductions of air pollutant emissions from well completions and other components of ancillary infrastructure have been demonstrated to reduce emission of methane, non-methane hydrocarbons, and VOCs during the oil and gas development process. Many of the non-methane VOCs contribute to background and

regional tropospheric ozone concentrations and some are directly health damaging (e.g., benzene, toluene, ethylbenzene, xylene, formaldehyde, and hydrogen sulfide). Therefore, a reduction in emissions could decrease exposure of populations, especially at the local level, to harmful air pollutants. For a more complete discussion of these types of air pollutant emission mitigation technologies, please refer to Volume II, Chapter 3.

The deployment of mitigation technologies that have a demonstrated ability to reduce emissions in the laboratory or in small studies in the field do not necessary translate to actual reductions in air pollutants at scale if the sources of pollution increase. For example, Thompson et al. (2014) found that although regulations that strengthen rules about emission-reducing technologies in Colorado are much more stringent today than in 2008, emissions of VOCs have increased because of expansion of oil and gas development.

6.8.1.3. Use of Produced Water for Agricultural Irrigation

As noted in Chapter 2 of this volume, at least seven cases were identified that allow produced water to be used in agricultural irrigation in the San Joaquin Valley, with testing and treatment protocols that are insufficient to guarantee that well stimulation and other chemical constituents are at sufficiently low concentrations not to pose public health and occupational (farm worker) risks. To reduce public health risks that are potentially associated with the use of produced water for irrigation, prior to authorization to use produced water for irrigation, California should develop and implement testing and treatment protocols which account for stimulation chemicals and the other possible chemicals mobilized in the subsurface, prior to approving beneficial reuse of water produced from fields with well stimulation (and logically any produced water).

6.8.1.4. Water Source Switching

As noted in Chapter 2 of this volume, subsurface disposal of recovered fluid and produced water (Class II Underground Injection Control (UIC) wells) has been conducted in aquifers that are suitable for drinking water and other beneficial uses. The majority of Californians do not source their drinking water from such wells, and there has been no groundwater monitoring in the state to determine the number or the extent to which drinking water aquifers may be contaminated by well-stimulation-enabled oil development. Concerned households can eliminate their potential exposure by being provided with alternative drinking water sources that are known to be safe. It should be noted that water source switching is not be an alternative to the protection of drinking water resources.

6.8.2. Occupational Health Mitigation Practices

6.8.2.1. Personal Protective Equipment

The research is limited on the use of personal protective equipment (PPE) in the oil and gas extraction industry. A study on worker health and safety during flowback noted the routine use of PPE by workers at all sites, depending on work task (Esswein et al., 2014).

The PPE observed in use included flame-retardant clothing, steel toe boots, safety glasses, hard hats, and occasional use of fall protection, riggers gloves, and hearing protection. None of the workers observed in this study who experienced the highest exposure to silica sand and chemicals (flowback technicians, production watch technicians, or water management technicians) was observed wearing respirators, nor were they clean-shaven, which is necessary for proper respirator protection. Workers who wore half mask respirators during mixing of crystalline silica proppant were also not sufficiently protected, indicating that a similar study to this NIOSH assessment should be performed in California to assess worker exposure on the well pad.

6.8.2.2. Reducing Occupational Exposure to Silica

Mulloy (2014) identified opportunities for reducing silica exposure, including: elimination; substitution of ceramic or alternative proppants; proper engineering controls that minimize respiratory exposure; administrative control that limit worker time on site; and personal protection. Other recommendations included conducting workplace exposure assessments to characterize exposures to respirable crystalline silica; controlling exposures to the lowest concentrations achievable (and lower than the OSHA PEL or NIOSH REL); and ensuring that an effective respiratory protection program is in place that meets the OSHA Respiratory Protection Standards (Esswein et al., 2013).

6.9. Data Gaps

We need four types of information to assess environmental public health hazards:

1. The source and identity of the chemical substances (or stressor such as noise, traffic, etc.) of concern

2. A qualitative or quantitative measure of the outcome of the stressor, such as an acute or chronic toxicity factor,

3. Quantification of an emissions factor to air and/or water or a reporting of the quantity used.

4. Information about the number and plausibility of human exposure pathways associated either with emissions or quantities used. This factor is useful for hazard assessments and essential for risk assessments.

In preparing this hazard assessment, we have found that only for a minority of cases do we have information for items (1) identity, (2) outcome measure, (3) quantity/emission, and (4) exposure pathways. It is more common that we have (1) but not (2) or (3); (1) and (3) but not (2); or (1) and (2) and not (3). In some cases, for example some of the unidentified or ambiguously described components for the well treatment mixtures, we lack information on (1), (2) and (3). To add to our uncertainty, we find that even in cases

where we have information about identity, toxicity, and/or quantity/emissions, there are significant concerns about the accuracy of the information.

6.10. Conclusions

The majority of important potential direct impacts of well stimulation result from the use of well stimulation chemicals. The large number of chemicals used in well stimulation makes it very difficult to judge the risks posed by accidental releases of stimulation fluids, such as those related to surface spills or unexpected subsurface pathways. Of the chemicals used, many are not sufficiently characterized to allow a full risk analysis.

There is a lack of information related to human exposure pathways for well-stimulation-enabled oil and gas development in California. For example, it is known that some produced water is diverted for agricultural use (see Chapter 2 in this volume); however, information regarding the composition of the fluids at the point of release and the environmental persistence, toxicity, and bioavailability of specific compounds in agricultural systems has not been studied. There is also a need to design and/or expand monitoring studies to better evaluate time activity patterns and personal exposure on and off-site for well-stimulation-enabled oil and gas development activities. Finally, it is important to extend the characterization of some on-site (occupational) exposures to off-site (community) exposures, i.e., for airborne silica proppant.

California-specific studies on the epidemiology of exposures to stimulation chemicals and stressors remain, by and large, non-existent. Although air and water quality studies suggest public health hazards exist, many data gaps remain, and more research is needed to clarify the magnitude of human-health risks and potential existing and future morbidity and mortality burdens associated with these concerns. It is clear that environmental public health science is playing catch up with well stimulation-enabled oil and gas development—and oil and gas development in general—across the country, and this is particularly notable in California.

Most of the studies included in this review of the literature were conducted in geographically and geologically diverse areas of the U.S., and may or may not be directly generalizable to the California context. Furthermore, much of the research on health risks has been conducted on the development of hydrocarbons from shale. While there are many similarities between the processes involved in the development of shale across the country and in the development of diatomite and other oil reservoirs in California, there are also a number of differences that increase and decrease public health hazards and potential public health risks (See Volume I).

There is no data on work-related fatalities related specifically to oil and gas development enabled by well stimulation, but the types of hazardous work activities during well stimulation are similar to those seen in general oil and gas extraction operations. Work-related fatality rates are significantly higher in the oil and gas development industry compared to the general industry average.

Work processes in oil and gas development, including that enabled by well stimulation, should be fully characterized to determine the specific risk factors for work-related injury and illness relative to risk factors for oil and gas production in general. Health effects among oil and gas development workers engaged in well stimulation should be monitored and evaluated to determine specific occupational health risk factors and harm-mitigation strategies to reduce the risk of deaths and serious injuries.

The current scientific literature and well stimulation chemical data available in California reveals that many of the well-stimulation-associated hazards have not been adequately characterized, nor have the associated environmental public health or occupational health risks been adequately analyzed—an observation that has been made by others (Adgate et al., 2014; Law et al., 2014; Kovats et al., 2014; New York Department of Health, 2014; NRC, 2014; Shonkoff et al., 2014). Studies of public health risk have failed to make clear whether the impact is caused by well stimulation or by oil development that is enabled by stimulation. Studies of health risks that differentiate the cause of the hazard would remedy this.

One of the most prominent key findings from our efforts to assess hazards is the significance of data gaps and the uncertainty that arises from these gaps in our confidence about characterizing human health risks for California.

This scientific literature review and hazard assessment, as well as other chapters in this volume, indicates that there are a number of potential human health hazards associated with well-stimulation-enabled oil and gas development in California with regards to air quality, water quality, and environmental exposure pathways. Our review also found that California-specific scientific assessments and datasets more generally on air, water, and human health are sparse. Additionally, human health monitoring data have not been adequately collected, let alone pursued. The hazard assessment of California-specific datasets on well stimulation chemistry indicates that more than half of the chemical constituents of stimulation fluids in California do not have any toxicity and/or use frequency or quantity information available, rendering it challenging to conclusively assess the magnitude of human health hazards associated with these processes. The emission of criteria and hazardous air pollutants have also only been monitored on the regional scale, and even in cases when these air pollutant emission factors are known, it is not possible, with the data available, to determine local emissions, community exposures, and subsequent population health risks.

We identified mitigation options that may reduce the magnitude of public health risks associated with well-stimulation-enabled oil and gas development in California; however, proper monitoring and enforcement are important components of sound mitigation that are often overlooked. Moreover, the data gaps that we identified create challenges in producing an adequately detailed assessment to provide clear guidance on the protection of public health, in the context of well-stimulation-enabled oil and gas development in California.

6.11. Recommendations

This chapter provides findings about what can and cannot be determined about potential impacts of well stimulation technology on human health, based on currently available information. One of the challenges that arise in efforts to study health risks for well-stimulation-enabled oil and gas development is the lack information available to carry out a standard hazard assessment and a broader risk characterization that requires information on exposure and dose-response. Here, we provide recommendations to address these information gaps.

6.11.1. Recommendation Regarding Chemical Use

The majority of important potential direct impacts of well stimulation result from the use of well stimulation chemicals. The large number of chemicals used in well stimulation makes it very difficult to judge the risks posed by accidental releases of stimulation fluids, such as those related to surface spills or unexpected subsurface pathways. Of the chemicals used, many are not sufficiently characterized to allow a full risk analysis.

Recommendation: *Operators should report the unique CASRN identification for all chemicals used in hydraulic fracturing and acid stimulation and the use of chemicals with unknown environmental profiles should be disallowed. The overall number of different chemicals should be reduced, and the use of more hazardous chemicals and chemicals with poor environmental profiles should be reduced, avoided or disallowed. The chemicals used in hydraulic fracturing could be limited to those on an approved list that would consist only of those chemicals with known and acceptable environmental hazard profiles. Operators should apply Green Chemistry principles to the formulation of hydraulic fracturing fluids.*

6.11.2. Recommendation Regarding Exposure and Health-Risk Information Gaps

This chapter identifies information gaps on hazards of substances used, the quantities and, in some cases, the identity of chemicals used for acidization and hydraulic fracturing, the magnitude of air emissions of well stimulation chemicals and fugitive emissions of oil and gas constituents, exposure pathways, and availability of acute and (in particular) chronic dose-response information.

Recommendation: *Conduct integrated research that cuts across multiple scientific disciplines and policy interests at relevant temporal and spatial scales in California, to answer key questions about the community and occupational impacts of oil and gas production enabled by well stimulation. Provide verification and validation of reported chemical use data, and conduct research to characterize the fate and transport of both intentional and unintentional chemical releases during well stimulation activities.*

6.11.3. Recommendation on Community Health

Oil and gas development—including that enabled by well stimulation—creates the risk of exposing human populations to a broad range of potentially hazardous substances (chemical and biological) or physical hazards (e.g., light and noise). For many of these hazards, we conclude that regional impacts associated with well stimulation activity are likely to be low, but exposures that can occur near well stimulation activity and enabled oil and gas development may result in elevated community health risks.

Recommendation: *Initiate studies in California to assess public health as a function of proximity to all oil and gas development, not just stimulated wells, and develop policies, for example science-based surface setbacks, to limit exposures.*

6.11.4. Recommendation on Occupational Health

Workers who are involved in oil and gas operations are exposed to chemical and physical hazards, some of which are specific to well stimulation activities, and many of which are general to the industry. Our review identified studies confirming occupational hazards related to well stimulation in states outside of California. There have been two peer-reviewed studies of occupational exposures attributable to hydraulic fracturing conducted by the National Institute for Occupational Safety and Health (NIOSH) across multiple states (not including California) and times of year. One of the studies found that respirable silica (silica sand is used as a proppant to hold open fractures formed in hydraulic fracturing) was in concentrations well in excess of occupational health and safety standards, in this case permissible exposure limits (PELs), by factors of as much as ten. Exposures exceeded PELs even when workers reported use of personal protective equipment. The second study found exposure to VOCs, especially benzene, above recommended occupational levels. The NIOSH studies are relevant for identifying hazards that could be significant for California workers, but no study to date has addressed occupational hazards associated with hydraulic fracturing and other forms of well stimulation in California.

Employers in the oil and gas industry must comply with existing California occupational safety and health regulations, and follow best practices to reduce and eliminate illness and injury risk to their employees. Employers can and often do implement comprehensive worker-protection programs that substantially reduce worker exposure and likelihood of illness and injury, but the effectiveness of these programs in California has not been evaluated. Engineering controls that reduce emissions could protect workers involved in well stimulation operations from chemical exposures and potentially reduce the likelihood of chemical exposure to the surrounding community.

Recommendation: *Design and execute California-based studies focused on silica and volatile organic compound exposures to workers engaged in hydraulic-fracturing-enabled oil and gas development processes, based on the NIOSH occupational health findings and protocols.*

6.12. References

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